THE UNIVERSITY OF QUEENSLAND

AUSTRALIA

Cost-effectiveness of Renewable Energy Subsidies in Reducing Greenhouse Gas Emissions in Australia

Donald John Burtt

Bachelor of Science in Pure Mathematics

Master of Commerce in Economics

Master of Philosophy in Economics

A thesis submitted for the degree of Doctor of Philosophy at

The University of Queensland in 2016

School of Geography, Planning and Environmental Management

ABSTRACT

The main focus of this thesis is an assessment of the cost-effectiveness of subsidies paid by electricity consumers to support the uptake of household photovoltaic (PV) in Australia, modelled over the period 2006 to 2014. This modelling is a component of a larger 20 year model, of small and large-scale renewable energy, developed to enable sensitivity analyses and policy scenarios to be undertaken of the effectiveness of renewable energy subsidies. In Australia subsidies are funded mostly by electricity consumers although there are some state and Commonwealth grants. Costs and revenues have been determined for each type of renewable energy over the period from 2000 to 2020 and converted to payback periods. For household PV, annual payback periods are regressed against the uptake of PV over the years 2006 to 2014 with sensitivity analyses run on input variables. The extent to which renewable energy has replaced coal and gas-fired energy is assessed to estimate the reduction in greenhouse gas emissions. The relationship of subsidies to emission reductions appears to be the first analysis of this kind in Australia.

Household PV sensitivity analysis revealed that the declining cost of PV panels had most impact on PV uptake followed by feed-in tariffs (FITs), renewable energy credits and increasing household electricity tariffs. Modelling suggests that FITs were higher than necessary to achieve the resultant levels of household PV uptake and that the low cost of PV panels and comparatively high electricity tariffs are likely to result in a continuing strong uptake of household PV in Australia.

Household PV subsidies peaked in 2011 and 2012, with payback periods falling to three to four years, having since increased to five to six years. Emission reduction costs are expected to reduce from AU$118 per t CO_2e in 2014 to AU$110 per t CO_2e in 2020, having peaked at AU$212 per t CO_2e in 2010. Household PV reduced Australia's emissions by 3.7 million t CO_2e in 2014 and are expected to reach 6.9 million t CO_2e (1.3 % of Australia's total emissions) by 2020.

Large-scale energy, not having the same level of subsidies as household PV, had payback periods upwards of 10 years prior to 2015 but have since fallen as a result of increasing large-scale generation certificate (LGC) prices increasing to over AU$70/LGC. Emission reduction costs for large-scale renewable energy averaged AU$47 per t CO_2e in 2014 and are forecast to reach AU$80 per t CO_2e by 2020. The trend difference is because household PV FITs expire over time whereas LGC prices have been increasing.

Sensitivity analyses suggest that household PV subsidies could have been AU$1 billion to AU$2 billion lower with minimal impact on the uptake of household PV. The outcome without subsidies produced an almost 50% uptake of actual household PV uptake, but little growth in large-scale renewable energy. Subsidies totalling AU$19 billion could have been saved over the period 2000 to 2020 but Australia would not have met its target of 20% of generation being from renewable energy sources by 2020.

Modelling suggested that in 2014 retail electricity prices would have been 12 % lower without subsidy payments and a further 14 % lower if network costs had increased at the same rate as other electricity cost components. The latter highlights the substantial increase in network charges which were argued were necessary “to keep the lights on”, which assisted in reducing emissions through reduced electricity consumption.

The model was extended to analyse the responsiveness of consumers to increasingly higher electricity prices, producing a price elasticity of demand for electricity in Australia over the period FY 2008 to FY 2015 of -0.4, being in line with other research. This means that consumer subsidies not only stimulated renewable energy output but, through higher retail electricity prices have also contributed towards emission reductions through reducing electricity consumption.

The analysis was extended to include the economics of battery storage associated with household PV, considered appropriate because of the decline in battery costs, and the forthcoming termination of high FITs. Together they are expected to make battery storage a viable option for many households in Australia in the near future. Battery payback periods are expected to fall from 25 to 12 years for smaller PV households and to decline to four years for larger (more than 4 kW) PV households.

In summary, renewable energy subsidies in Australia will total nearly AU$20 billion over the period 2001 to 2020, a cost born by electricity consumers. The outcome is that Australia will very likely meet its 2020 target of 20% of generation being from renewable energy but whether the 5% reduction in emissions will also be achieved is also dependent on emission reductions in other areas, including the success of the government’s Direct Action Plan. Household PV subsidies could have been restructured to achieve more cost effective outcomes, with AU$1 billion to AU$2 billion savings having been possible with little uptake impact.

Declaration by author

This thesis is composed of my original work, and contains no material previously published or written by another person except where due reference has been made in the text. I have clearly stated the contribution by others to jointly-authored works that I have included in my thesis.

I have clearly stated the contribution of others to my thesis as a whole, including statistical assistance, survey design, data analysis, significant technical procedures, professional editorial advice, and any other original research work used or reported in my thesis. The content of my thesis is the result of work I have carried out since the commencement of my research higher degree candidature and does not include a substantial part of work that has been submitted to qualify for the award of any other degree or diploma in any university or other tertiary institution. I have clearly stated which parts of my thesis, if any, have been submitted to qualify for another award.

I acknowledge that an electronic copy of my thesis must be lodged with the University Library and, subject to the policy and procedures of The University of Queensland, the thesis be made available for research and study in accordance with the Copyright Act 1968 unless a period of embargo has been approved by the Dean of the Graduate School.

I acknowledge that copyright of all material contained in my thesis resides with the copyright holder(s) of that material. Where appropriate I have obtained copyright permission from the copyright holder to reproduce material in this thesis.

Publications during candidature

Peer-reviewed paper

Burtt, D., Dargusch, P. (2015), The Cost-effectiveness of Household Photovoltaic Systems in Reducing Greenhouse Gas Emissions in Australia: Linking Subsidies with Emission Reductions, *Applied Energy 148 (2015)* 439-448

Conference paper

An abbreviated version of the Applied Energy paper *The Cost-effectiveness of Household Photovoltaic Systems in Reducing Greenhouse Gas Emissions in Australia: Linking Subsidies with Emission Reductions* was presented on 1 October 2015 at the 14th International Conference on Clean Energy (ICCE 2015) in Saskatoon, Canada.

The ICCE 2015 organizing committee advised that the paper had been selected as the "Outstanding Student Paper" presented at the Conference.

Publications included in this thesis

No publication has been included as a separate chapter in this thesis, as the structure of the thesis did make this possible. However the following published *Applied Energy* paper was included in its entirety, spread between various thesis sections.

Burtt, D., Dargusch, P. (2015), The Cost-effectiveness of Household Photovoltaic Systems in Reducing Greenhouse Gas Emissions in Australia: Linking Subsidies with Emission Reductions, *Applied Energy 148 (2015)* 439-448

Applied Energy section	Thesis section
1. Introduction	pts 4.1, 4.2, 4.3
2. Literature review	
2.1	2.1.1
2.2	2.1.2
2.3	2.4
2.4	2.1.3, 5.6.1
3. Modelling approach	
3.1 to 3.5	5.6.2
3.6	5.6.3
4. Model Results	6.1
4.1 to 4.9	6.1.1 to 6.1.9
5. Energy Storage	part 2.3
6. Conclusions	6.6, pt 8.4

Contributors

Contributor	Statement of contribution
Don Burtt (Candidate)	Wrote the paper (100%) Edited the paper (90%)
Paul Dargusch	Edited the paper (10%)

The author had the following M Phil. paper published in 2009:

Burtt, D. (2009), *Electricity Deregulation and Vertical Integration*, Lambert Academic Publishing AG & Co. KG, Germany

This paper is referenced in thesis Chapters 2, 4, and 5.

Contributions by others to this thesis

No Contributions by others.

Statements of parts of the thesis submitted to qualify for the award of another degree

None

Acknowledgements

I would like to acknowledge assistance provided by my principal supervisor A/Prof. Paul Dargusch and associate supervisors Professor John Foster and Dr Liam Wagner. I am grateful for industry knowledge and thesis feedback provided by Ian Rose, Alan Millis, Bob Graham, Mark Williamson, Walter Schutte, Steve Goyen, Paul Simshauser and fellow students Adrian Ward and Scott Agnew. The university scholarship is greatly appreciated.

Keywords

Renewable energy, solar, photovoltaic, emissions, subsidies, pay back periods.

Australian and New Zealand Standard Research Classifications (ANZSRC)

ANZSRC code: 140205, Environment and Resource Economics, 60%

ANZSRC code: 850504, Solar PV Energy, 30%

ANZSRC code: 850599, Renewable Energy not elsewhere classified, 10%

Fields of Research (For) Classification

FoR code: 0502, Environmental Science and Management, 70%

FoR code: Applied Economics, 30%

TABLE OF CONTENTS

List of Figures

List of Tables

List of Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator, the entity that manages dispatch and planning in the National Electricity Market.
ARENA	The Australian Renewable Energy Agency, a statutory authority of the Commonwealth Government that provides renewable energy finance
AU$	Australian dollar
bagasse	A renewable fuel produced from sugar cane waste
bn	billion
BREE	Bureau of Resources and Energy Economics, a Commonwealth Government research agency
CCS	carbon capture and storage
CDM	Clean Development Mechanism
CEFC	Clean Energy Finance Corporation
CER	Clean Energy Regulator (or Certified Emission Reduction relating to EU ETS)
CIF	carbon intensity factor
CO_2	carbon dioxide, the most common greenhouse gas
CO_2e	carbon dioxide equivalent
DSM	demand-side management
ERF	Emissions Reduction Fund
ERU	Emission Reduction Unit
ETS	Emissions Trading Scheme
EU	European Union
EUR	euro dollar
GJ	gigajoule
GWh	Gigawatt hour
ICE	Intercontinental Exchange

kW	kilowatt
kWh	kilowatt-hour
LGC	Large-scale Generation Certificate, a certificate that can be created and traded under the LRET.
LRET	Large-scale Renewable Energy Target, the Commonwealth's scheme to promote large-scale renewable electricity generation.
LRMC	long-run marginal cost
m	million
MRET	Mandatory Renewable Energy Target
MW	megawatt
MWh	megawatt-hour
NEM	National Electricity Market, the interconnected electricity grid linking New South Wales, Victoria, Tasmania, South Australia and most of Queensland.
PEDE	price elasticity of demand for electricity
PV	photovoltaic
REC	Renewable Energy Certificate
RET	Renewable Energy Target
SRES	Small-scale Renewable Energy Scheme
SRMC	short-run marginal cost
STC	Small-scale Technology Certificate
TOU	time-of-use (meters)
TWh	terawatt hour (being 1,000 MWhs)

Chapter 1 Introduction

Summary

The Introduction explains, in an Australian context, (1) the importance of the renewable energy sector in reducing Greenhouse Gas (GHG) emissions, (2) subsidy-related renewable energy sector issues, (3) the research questions answered in this thesis, (4) the significance of the research, (5) methodology used, (6) the author's professional experience in the energy sector as far as it relates to this research, and (7) the structure of this thesis.

1.1 Background

This thesis is predicated on the assumption that climate change is a major global problem and that the primary driver of climate change is GHG emissions. The importance of taking corrective action to address climate change is summed up by Orszag (2008) in his testimony to the US House of Representatives:

> Global climate change is one of the nation's most significant long-term policy challenges. Human activities are producing increasingly large quantities of greenhouse gases, particularly CO_2. The accumulation of those gases in the atmosphere is expected to have potentially serious and costly effects on regional climates throughout the world. Although the magnitude of such damage remains highly uncertain, there is growing recognition that some degree of risk exists for the damage to be large and perhaps even catastrophic.
>
> The risk of potentially catastrophic damage from climate change can justify taking action to reduce that risk in much the same way that the hazards we all face as individuals motivate us to buy insurance. Some of society's resources may best be devoted to addressing climate change even if the most severe damage ultimately does not materialize.
>
> Reducing greenhouse-gas emissions would be beneficial in limiting the degree of risk associated with climate change, especially the risk of significant damage. However, decreasing those emissions would also impose costs on the economy – in the case of CO_2, because much economic activity is based on fossil fuels, which release carbon in the form of that gas when they are burned. Much of those costs will be passed along to consumers in the form of higher prices for energy and energy-intensive goods (Orszag, 2008, p 1).

The focus of this thesis is on the contribution that the electricity sector, and in particular the renewable energy sector, can make in helping to reduce GHG emissions in Australia. GHG emissions from the electricity sector increased from 40 to 45% of total Australian GHG emissions over the last 20 years (Australian Government Department of Climate Change and Energy

Efficiency, (2012a). Countering fossil fuel generation growth is the growth in renewable energy from 8% of total electricity output in 2000 to 15% in 2015 (BREE, 2013; Clean Energy Council, 2015). Recent renewable energy growth is mostly due to household PV having increased from 23 MW in 2008 to 4,000 MW in 2015 (AEMO, 2012; Clean Energy Council, 2015), being 2.4% of total energy output (Clean Energy Council, 2015).

The analysis presented in this thesis covers the period from 2000 to 2020, being the period during which the Australian Government committed, in 2011 as part of the Clean Energy Futures Plan, to reduce GHG emissions by 5% compared with 2000 levels as well as seeking to have at least 20% of electricity generation from renewable energy sources (Clean Energy Regulator, 2012a). Although the analysis does not extend beyond 2020 the ongoing subsidy-related renewable energy incentives will ensure ongoing emission reductions, being a necessary part of future emission reduction targets, the most relevant being reduction of GHG emissions by 80% by 2050 (Climate Change Authority, 2014).

Australia's approach to reducing GHG emissions has been wide-ranging including energy conservation measures, land clearing incentives and state government schemes such as the Queensland's 13% gas scheme and the NSW Greenhouse Gas Abatement scheme. This thesis however examines only subsidy-related renewable energy schemes applying nationally that by impacting on electricity generation or electricity consumption reduce GHG emissions. The first such scheme took effect in 2001 through the establishment of a mandatory renewable energy target (MRET) scheme, followed by having a price on carbon on 1 July 2012, terminating in June 2014, and more recently, following a change in government, introducing what is known as the Emissions Reduction Fund and Direct Action Plan (DAP). In addition states introduced feed-in tariffs (FITs) for household PV, the first commencing 1 July 2008. Renewable energy scheme costs and FITs are passed on directly by retailers to electricity consumers. The price on carbon is initially borne by electricity generators who, to the extent competition allows, pass this on in higher wholesale electricity prices to retailers who pass on to electricity consumers. The DAP is funded directly by government.

The MRET was restructured in 2009, to become the renewable energy target (RET), providing separate targets and separate penalties to electricity retailers for not securing minimum renewable energy credits from small-scale, mostly household photovoltaic (PV), and large-scale renewable energy projects. The history of MRET and RET schemes is discussed in more detail in Section 4.2. Large-scale renewable energy schemes initially had the most impact on reducing GHG emissions but increasingly attractive household PV incentives resulted in substantial growth in household PV with emission reductions exceeding the most optimistic expectations.

1.2 Research problem

Emission reduction policies have been implemented in many countries and regions around the world (Honghang et al, 2014a; Dusonchet and Telaretti, 2015; REN, 2016) most often, based on a literature search, without an evaluation of the cost-effectiveness of these schemes. This was also observed in Australia's case by Oliva and MacGill (2013) who commented "There has been a lack of a long term economic assessment of these (referring to PV policy support) in Australia, from both a social and a private perspective, which has ended up in unsustainable and economically inefficient programs" (Oliva and MacGill, 2013, p 1). In Australia, policy decisions are made at both the Commonwealth and state levels, generally with the parties acting independently of each other so that funding allocated towards emission reduction policies is not being effectively used to meet national emission reduction and renewable energy targets. The influence of governments at different levels and the possibility of changes in the parties in power, who may change existing policies, has resulted in some investment uncertainty jeopardising the effectiveness of renewable energy policies. At the Commonwealth level the only real bipartisan stability has occurred in the unwritten agreement to support a renewable energy scheme, but this may change as renewable energy targets beyond 2020 have yet to be finalised.

The research challenge is the need to provide more reliable information on the cost-effectiveness of Australian government's renewable and emission reduction policies. Research by organisations such as the Productivity Commission, Treasury, ACIL Tasman, ROAM Consulting, SKMMMA and Frontier Economics, provide valuable information but they cannot overcome political uncertainty and are generally not in the same level of detail as in this thesis.

1.3 Research questions

The purpose of this thesis is to provide information that assists Australian policy makers in developing long-term electricity sector emission reduction policies by answering the following questions:

1. How do renewable energy schemes compare with the efficiency of other emission reduction schemes?

2. How cost-effective have household roof top PV[1] subsidies been in reducing GHG emissions in Australia?

3. What lessons can be learnt from household PV incentive schemes, particularly regarding how incentive schemes could have been better structured?

4. How would the level of output and emission reductions have changed if subsidies for small and large-scale renewable energy had been at lower levels?

5. What is the likelihood that Australia will meet its renewable energy and emission reduction targets in 2020?

This thesis utilises a model developed for the purpose of answering these questions. The model enables quantification of the cost of subsidies, both in absolute terms and in cost per tonne of reduced GHG emissions from renewable energy in Australia, to show which schemes have been relatively cost effective.

1.4 Justification for this research

The spending of substantial amounts of money, being either directly by government or through levies imposed on electricity consumers, is a contentious matter, not always showing clear benefits. This thesis attempts to reduce the level of contention through objective analysis to measure costs and benefits, such that an assessment can be made as to whether such money or levies are "well spent" or appropriately imposed. The level of contention can be reduced if renewable energy output and GHG emissions from reduced subsidy levels were better understood, and meaningful alternatives suggested, being important information for policy makers.

The model developed enables examination to be made of the level of subsidies associated with each type of renewable energy, associated emission reductions and their unit costs. It is sufficiently generic that it could be applied in other countries where renewable energy subsidies have been introduced[2].

A 20 year model has been developed that produces payback periods for household PV and large-scale energy types: solar; wind; hydro, bagasse and biomass energy generation, enabling

[1] Availability of data has meant that the analysis also includes small-scale commercial (less than 100 kW) PV.

[2] This comment was made by one of the reviewers of the author's paper published in the journal *Applied Energy*.

sensitivity analyses to be undertaken, an approach that does not appear to have occurred in Australian or overseas. Neither does the household demand-side management component, defined as electricity demand response to higher retail electricity prices, producing price-demand elasticities, appear to have been modelled in Australia, although overseas research is common. A particularly novel aspect of the research is the in-depth analysis of the financial aspects faced by households in deciding whether or not to install PV, developing payback periods, and then using regression analysis to relate payback periods to the actual uptake of PV. A further novel aspect is the use of half-hourly PV output data, for a full year, to determine the types of generation displaced so that reductions in GHG emissions can be measured and matched against the level of subsidies involved. Outcomes with and without subsidies were used to determine the impact of subsidies on levels of emission reductions and the extent to which 2020 targets might or might not be met.

1.5 Overview of methodology approach

A 20 year model has been developed that captures costs, subsidies and revenues associated with renewable energy projects on an annual basis. Five categories of renewable energy types are examined: household rooftop PV; large-scale solar; hydro, wind, bagasse and biomass, although for data availability reasons biomass is viewed in less detail than the others. Household PV is examined in most detail because it involves a range of incentives and has been an effective emissions reduction scheme. A regression model relates payback periods to the actual uptake of household PV over the period FY 2006 to FY 2014.

Non-renewable energy is viewed according to the switch from coal-fired to gas-fired generation particularly over the carbon price years of FY 2013 and FY 2014. Energy conservation, in effect energy reduction, is viewed according to the reduction in demand associated with increases in real electricity prices, creating a price elasticity of demand. Sensitivity analyses are undertaken of input costs and subsidies, wherever possible. Household PV regression analysis covers nine years whereas the full analysis is from FY 2000 to FY 2020 encompassing the period the Australia Government has committed to reducing GHG emissions by 5% as well as seeking to have at least 20% of electricity generation from renewable energy sources (Clean Energy Regulator, 2012a). A more complete explanation of the methodology used is contained in Chapter 5, with additional detail in Appendix A.

1.6 Structure of this thesis

This thesis has been structured as follows:

Chapter 1 Introduction

This chapter includes objectives of this thesis, originality of research and methodology adopted.

Chapter 2 Review of Renewable Energy-Related Literature

This chapter discusses published research on household PV and large-scale renewable energy, with emphasis on variations in subsidies worldwide. It also examines renewable energy in the context of energy storage, relationship with other emission reduction schemes and the future of renewable energy world-wide.

Chapter 3 Climate Change Reality and World-wide Greenhouse Gas Emission Reduction Schemes

This chapter discusses whether there is in fact a climate change issue, and if so what are the options available to address it. A broad view is first taken of the difference between “price” and “quantity” emission reduction schemes, in the context of carbon pricing, cap and trade and renewable energy schemes. World-wide GHG emission reduction schemes are examined with a focus on emission reduction schemes in the European Union, including analysis of baseline issues.

Chapter 4 Australia’s Approach to Reducing Greenhouse Gas Emissions

This chapter discusses the history and current situation concerning electricity-related emission reduction schemes in Australia, including reference to the rapid growth in household PV and opportunities for households to reduce emissions.

Chapter 5 Methodology

This chapter begins with the approach taken that lead to modelling the various emission reduction schemes proposed and adopted in Australia, leading to the four part modelling approach adopted. Each of these four model components is discussed in some detail. Comments are also included on aspects not modelled, such as network and back-up generation issues associated with renewable energy.

Chapter 6 Model Results

This chapter discusses household PV model outcomes including costs per tonne of CO_2e emitted and examines the sensitivity of outcomes to changes in input data such as subsidy levels and PV panel costs. The subsidy costs of large-scale renewable energy output, being large-scale solar, hydro, wind and bagasse, are examined with comments on the likelihood of Australia achieving its emission reduction and renewable targets in 2020. These costs are compared with emission reduction costs in other countries.

Chapter 7 Sensitivity of Model Results to Reduced Subsidy Levels

The sensitivity of renewable energy output to reduced subsidy levels is viewed for each of household PV and large-scale renewable energy, including the extreme example of no subsidies. The outcomes are used to evaluate whether Australia's emission targets could be met at lower subsidy levels.

Chapter 8 Conclusions and Policy Implications

This chapter discusses policy implications for household PV including FIT policy options and the future of renewable energy in Australia. Opportunities for households to more actively contribute to reducing emissions are discussed.

Appendix A Model Explanation

This appendix contains five sections being parts of this thesis explained in more detail, being: how the household PV model was developed, how generation data was used retail electricity prices developed, how the large-scale renewable energy model was developed, reconciliation of renewable energy output with data contained in the REC Registry and a list of references containing data used only in the models developed.

Chapter 2 Literature review of subsidies and viability of renewable energy

Summary

Chapter 2 is a literature review mainly covering subsidies that support renewable energy world-wide and the overall economics of renewable energy. It does not relate to Australian developments, which are covered in later chapters. There is particular emphasis on research that relates to the model that has been developed, and associated policy implications.

The initial focus is on feed-in tariffs (FITs) which are a key form of small-scale renewable energy subsidy. Large-scale renewable energy subsidies are also examined particularly because of their current and expected future importance in helping ensure Australia meets its renewable energy targets.

The improving economics of energy storage, household PV and large-scale renewable energy are examined to determine whether viability is still possible at lower subsidy levels and even possibility without subsidies at some stage.

The literature review ends with the relationship between renewable energy schemes and other electricity-related schemes designed to reduce GHG emissions, and also discusses how renewable energy, non-renewable energy and energy storage might best be integrated.

The chapter that follows takes a global view of climate change to help provide a perspective of the importance of renewable energy schemes, including a world-wide analysis of renewable energy schemes. Carbon trading schemes are also examined but only in the context of how they relate to renewable energy schemes.

The review, in effect, examines different types of incentives or subsidies designed to support renewable energy, and the extent to which, as relative costs change over time, these incentives or subsidies are less likely to be needed.

2.1 Subsidies stimulating household PV

The literature review for solar energy has been separated into world-wide subsidies, variations in FITs, being the most common type of household PV subsidy, and the possibility of household PV reaching grid parity, reflecting continually declining PV costs, so that subsidies would no longer be required.

2.1.1 *World-wide subsidy support for household PV*

An increasing number of countries has introduced renewable energy subsidies with a particular focus on household PV, supported by FITs, which were first introduced by Germany (Bakhtyar et al, 2014), and less commonly supported by RECs. Honghang et al (2014a) determined that in 2014 there were 75 jurisdictions world-wide having solar energy FITs and 14 having renewable energy credit policies, having increased from 50 and ten respectively in 2010 (Schmalensee, 2012). A comprehensive review of FITs in EU countries is provided by Dusonchet and Telaretti (2015).

Australia's household PV subsidy structure differs from those in other parts of the world in that there is both a nation-wide subsidy and state subsidies. The nation-wide subsidy is in the form of small-scale technology certificates (STCs), earlier known as RECs, being a capital cost subsidy. An STC represented each MWh of PV output, which for PV systems in excess of 1.5 kW were deemed to total two STCs per annum, totally a maximum of 30 STCs over a 15 year period. State subsidies are FITs, varying by state, having differing terms with some FITs being on a gross (that is all PV output) basis and some on a net (that is exports only) basis. The relative merits of REC and FIT schemes are discussed in Sun et al (2015) concluding that it is difficult to show which is more effective while Tamas et al (2010) concluded that the schemes would have identical effectiveness in perfectly competitive markets. Authorities in Australia, as in most countries, underestimated the uptake of PV which was driven mainly by the unexpected rapid decline in the price of PV panels (Australian PV Association, 2011). This has resulted in many countries reviewing the ongoing nature of household PV subsidies, particularly FITs.

2.1.2 *Variations in types of feed-in-tariffs*

The provision of comparatively high fixed FITs in some Australian states, continuing for five to 20 years, and the ongoing high cost, begs the question of whether a different type of FIT could have been adopted (Parliament of Australia, 2011).The level and ongoing nature of FITs is also a concern in many other countries, including the United Kingdom (Cherrington et al, 2013), Spain (de la Hoz, 2014), Italy (Antonelli et al, 2014) and Greece (Danchev et al, 2010), and recognised by Hsu (2012) in providing FIT policy suggestions for Taiwan. The Australian case of three years of high FITs is similar to the experience in the United Kingdom, where attractive FITs resulted in strong PV growth. Cheerington et al (2013) noted that the UK government was considering reducing the FIT by 50% concluding, from case studies, that "a healthy return on investment can still be made" (Cheerington et al, 2013, p 421).

Japan introduced installation-cost subsidies for residential PV in 1994 followed by a FIT scheme in 2009 of EUR34 per kWh (Muhammad-Sukki et al, 2014). In August 2011, following the Fukushima disaster, this was expanded to include wind, geothermal, hydro and biomass, with a target of 20% to 35% of energy from renewable sources by 2013. Since July 2012 the FIT rate for small scale solar has been EUR30 per kWh with payback periods varying between 7 and 9 years. Their analysis suggests that Japan has had a carefully constructed FIT regime, stimulating PV without the highs and lows experienced by many other developed countries.

Ouyang and Lin (2014) determined that, in China, the current FIT of 5 percent capital costs is inadequate to support renewable energy growth needed to meet emission reduction targets (of 40 to 45% reduction on 2005 levels by 2020) with increased FITs being the most desirable means of achieving this target. In Ireland the economics of household PV has not been attractive (li et al, 2011). Ayompe and Duffy (2013) evaluated PV viability in Ireland under three FIT scenarios for three user type categories, resulting in substantial savings compared with a single FIT, for a similar uptake level.

Some of the many suggestions on FIT improvements include comments by Couture and Gagnon (2010) who suggested two types of FITs, those having a fixed price, with variations such as CPI adjustment and front loading, and those linked to market electricity prices. Lesser and Su (2008) suggested including a market component by having a “two part tariff, consisting of both a capacity payment and a market-based energy payment” (Lesser and Su, 2008, p 981) while Jenner et al (2013) commented on seven different FITs, most of which are currently in place in European countries. Of relevance in an Australian context are comments made by Leepa and Unfried (2013) to allow “FIT adjustments related to the changes of photovoltaic panel prices” (Leepa and Unfried, 2013, p 536). Also relevant is the suggestion made by Byrnes et al (2013) that FITs be “reviewed regularly to ensure that market distortions are not excessive” and that “FITs are reduced “once technology maturity and integration increases” (Byrnes et al, 2013, p 717). Danchev et al (2010) expressed similar views in relation to Greece which changed in 2009 from a fixed to a de-escalating FIT.

A market-related FIT policy has been deployed in Germany (Grau, 2014) but there are critics (Fais et al, 2014) who suggest that the FIT and REC regimes in Germany could be better structured taking closer account of policy objectives. Zhou et al (2011) and Ringel (2006) have similar views in stressing the importance of distinguishing between renewable energy subsidy schemes which are *effective*, in being capable of achieving goals, and those which are *efficient*, in minimising costs in achieving goals. Several commentators, including Reuter et al (2012) argue that the uncertain future of FIT regimes in some countries has been limiting renewable energy growth.

A reverse auction process of determining FITs has been suggested by several authors. Mayr et al (2014) modelled a reverse auction for household PV in Austria concluding that savings of 20% to 41% could be achieved compared with the current first-come first-served policy. In Australia a reverse auction FIT was suggested by Buckman et al (2014) in regard to a 40 MW solar energy plant in the Australian Capital Territory. Although this is substantially larger than household PV capacities it is a similar concept, utilising both market prices and a competitive process to determine a FIT level. These policy suggestions are not too late for some counties, such as Mexico, where FITs in other countries are being examined to determine best FIT policy options (Mundo-Hernandez, 2014).

There is a further issue of whether any form of FIT should apply when existing FIT contracts terminate, so that renewable energy projects can continue to be competitive. Uran and Krajcar (2013) suggest that a new FIT could apply which included a component in the form of the wholesale electricity price, a concept likely to have application in Australia in the near future as FITs expire on a state by state basis. As well as the type of feed-in tariff being important to be effective in the case of developing countries the comment has been made that there is also the need to address technical, regulatory issues and financial barriers (Rickerson et al, 2013).

2.1.3 *World-wide trend in the improving economics of household* PV

Household PV in Australia has become increasingly attractive with payback periods having fallen to between three and four years (Burtt and Dagusch, 2015), although the time period has since risen to over five years as a result of the reduction in subsidies. This begs two questions: how does this compare with other countries and what is the likely trend for the future?

O'Flaherty et al (2014) examined payback periods between 2007 and 2009 on 23 buildings in South Yorkshire. REC benefits were first available but they were subsequently replaced by FITs so that both types of benefits were not available at the same time. With RECs, payback periods were at least 60 years and with FITs they were as low as 14 years. Muhammad-Sukki et al (2014) calculated household PV payback periods in the order of 8 years in Japan follow introduction of FITs on 1 July 2012, concluding that a strong uptake will continue. Muhammad-Sukki et al (2014) undertook similar analyses for Germany, Italy and the United Kingdom resulting in payback periods of 15, 9 and 9 years respectively. They added that although solar only contributed to less than 1% of electricity generated in Japan prior to the Fukushima event the new FIT generates "an acceptable payback period" (Muhammad-Sukki et al, 2014, p. 642).

These results support the growth in household PV in Italy and the United Kingdom but with the strong growth of household PV in Germany it would appear there might be some additional German incentives not included. Plante (2014) undertook a similar exercise in a USA context arriving at a payback period of 15 to 17 years but with the inclusion of federal and tax credits this reduces to 9 to 10 years. It is worth noting that none of these payback periods is as low as those applying in the peak of subsidies provided in Australia in 2011 and 2012.

2.2 Subsidies stimulating large-scale renewable energy

The main focus in this thesis is household PV and the extent to which different types of subsidies have provided the greatest growth stimulus. For large-scale renewable energy the prime stimulus in Australia has been renewable credits in the form of large-scale generation certificates (LGCs), for output in excess of average 1994, 1995 and 1996 levels (Appendix A-4). In countries other than Australia there are often specific FITs designed to encourage renewable energy from a wider range of renewable energy sources, in effect substituting for Australia's LGC concept.

The extent to which different types of renewable energy incentives, for example grants, tax exemptions, green certificates and FITs, are most likely to be effective was examined by Burer et al (2009), through a survey of 60 investment professionals in Europe and North America. Of 12 possible "market pull" policies, FITs rated 4.2 out of a maximum 5.0, no others being above 3.6 and renewable certificates being one of the lowest rated at 3.2. The likelihood of least possible government intervention in the case of FITs was seen as a key factor in these results.

2.3 The improving economics of energy storage

There is the potential for household PV to obtain increased benefits through the storing of excess electricity at times when it is not needed, for later use (Bahadori, 2013). In an Australian household context Speidel and Braunl (2016) examined the improving economics of battery storage, aided by declining PV costs and the expected continuing reduction in battery costs.

The use of battery storage reduces the need for peaking electricity generation, giving rise to possible long-term benefits to consumers. Unfortunately the outcome provides real challenges for network companies, particularly if households become energy independent and therefore off grid (Agnew et al, 2015). Utilities are seeing this as a real threat, requiring a review of their business models (Rocky Mountain Institute, 2014).

The three main limitations to households achieving energy storage benefits are one-part household tariffs, not showing variations reflective of wholesale electricity prices, cost and availability of time-of-use meters (Burtt, 2009) and the cost of storage (Schleicher-Tappeser, 2012; Mayr et al, 2014). Edis (2014) summarised results from seven authors showing the cost of battery storage had declined by an average 40% between 2011 and 2014, with a further reduction of 35% expected between 2014 and 2020. In a Japanese context Komiyama and Fujii (2014) concluded that better use of LNG combined cycle plant and lower battery costs were necessary to secure the full potential of PV.

Chiang et al (1998) examined the most efficient relationship between household PV output, household consumption and battery storage system to determine how to most cost-effectively satisfy a utility’s power requirements. An experimental 600 watt system was used concluding that although set-up costs made the proposal uneconomic this could change in the future. Zahedi (2011) provided similar comments particularly in regard to the value of energy storage in improving overall PV reliability.

On a larger scale, in the wholesale market there are benefits through storage occurring when wholesale electricity prices are low for later exporting to the grid at times of high (peak) prices. This was recognised by Dominguez et al (2012) noted, in a Spanish context, who noted that molten salt storage has the potential to improve the economics of a large-scale concentrating power plant. The economics of large-scale hydro has similarly benefitted through pump storage, whereby water is pumped uphill to a catchment area to be later released, to flow through hydro-turbines at times of high electricity prices (PIN, 2013; IEA, 2014a). Australian examples include the Wivenhoe power station, Southern Hydro and Snowy Hydro.

The increasing focus on energy storage has prompted research into the most efficient types of battery systems. Yang et al (2011) examined the technical efficiency of a wide range of electrochemical battery types concluding that “the applications in terms of capacity, siting, performance parameters, etc. need to be further refined” (Yang et al, 2011, p. 3605). Xiaosong et al (2014) examined three energy storage systems a Li-ion battery, a supercapacitor pack and a combination of the two to determine which was most cost effective in powering a hybrid powertrain, concluding that in general the hybrid option was most cost effective but the outcome could vary depending on battery and diesel costs. Utilisation of used electric vehicle batteries is seen by Heymans et al (2014) as a valuable energy storage option particularly for peak load shifting. The outcome however was not seen to be economic without government incentives, but with the possibility of a greater uptake of electric vehicles in future this could eventually become a viable option.

Although not modelled in detail in this thesis the subject of energy storage and the associated economics for household PV has been analysed in Section 6.1.10 by considering possible outcomes when household FITs expire.

2.4 Future viability of household PV

The continuing decline in the cost of solar panels (Ghosh, 2014; Trancik, 2014) has caused speculation as to whether, at some time in the future, it is possible that PV may be economic without subsidies (Frankel, 2012; Schleicher-Tappeser, 2012). The concept of being "economic" is generally viewed in the context of being similar to household electricity tariffs (known as "grid parity") rather than being similar to wholesale market electricity prices (Bazilian et al, 2013, p 334). The concept of "grid parity" should, according to Elliston et al (2010) and Bazilian et al (2013), be treated with some caution as electricity tariffs are not always representative of underlying energy and network costs, and this could change in future making the concept of grid parity, especially in the case of multi-part tariffs, more problematic. Brazilian et al. (2013) also noted that because household tariffs are set differently around the world, inter-country comparisons should be treated with caution. Nevertheless there is widespread view that "solar PV grid parity has already been achieved in a number of countries/regions" (Bazilian et al, 2013, p 335), even up to four years ago in parts of the USA (Branker et al, 2011), imminently in Italy (IEA, 2012) and parts of China (Rigter and Vidican, 2010 and Honghang et al, 2014b). Fokaides and Kylili (2014), in a Cyprus context, noted that, because of the rapid reduction in PV costs, predictions of grid parity in the 2016 to 2020 era need to be brought forward such that grid parity may have already occurred in some locations. There is not however a consensus view with Holdermann et al (2104) concluding, in the context of each of Brazil's 63 distribution networks, that PV is not viable in either the commercial or residential sectors.

2.5 Future viability of large-scale renewable energy

Jakob (2012) analysed the extent to which subsidies are required to enable renewable energy projects viable. His analysis showed that levelised costs of solar energy were much greater than for other types of renewable energy, with wind being only about 25% that of solar energy. These figures suggest that it would be some time before large-scale solar would be viable without subsidies. However his figures are at 2005 and there have been substantial solar cost reductions since then, highlighting how far solar has progressed. Reichelstein and Yorston (2013) reached similar conclusions in a USA context noting that utility-scale PV installations are not yet cost competitive with fossil fuel power plants and that in contrast, commercial-scale installations have already attained cost parity, being comparable with retail electricity prices. Wind generation is also close to not requiring a subsidy, according to Frankl (2012).

Delucchi and Jacobson (2011) viewed the extreme situation of world energy being supplied 100% by renewable energy, with various means of addressing output volatility including storage. They concluded that the cost would be similar to the cost today and that the barriers are “primarily social and political, not technological or even economic” (Delucchi and Jacobson, 2011, p 1170).

Various authors have examined the likely future of large-scale renewable energy in Australia. Some attempted to view the outcome if there was a substantial increase in renewable energy, possibly in anticipation of larger GHG emission targets in the future. Elliston, MacGill and Diesendorf (2013) undertook modelling in an Australian context concluding that if emissions were to be dramatically cut, 100% renewables would be cheaper than any mix of fossil fuel and gas generation scenarios. Simshauser and Docwra (2004) came to a similar conclusion in using a range of modelling assumptions to conclude that no mix of coal and gas generation can cause GHG emissions to reduce sufficiently to enable Kyoto targets to be met as did Buckman and Diesendorf (2010a), through modelling, but only in relation to Australia attempting to meet its MRET target. They concluded that feed-in tariffs, a carbon price from an emissions trading scheme and renewable energy certificate prices will not be sufficient for the MRET target to be met. In a more recent paper Buckman and Diesendorf (2010b) concluded that low LGC prices will only support wind projects and that other forms of renewable energy will need their own incentives (Buckman and Diesendorf, 2010b). It should be noted that these comments are made prior to the upsurge in LGC prices in early 2015.

AEMO (2013) concluded that a 100% renewable energy scenario was possible in Australia but wholesale electricity prices would need to be a little over double current levels. The principal underlying factor was additional capacity required, in excess of peak demand to ensure reliability of supply. Currently the excess is in the order of 15% to 25% but under a 100% renewables scenario this would need to be 100% to 150%, reflecting in particular the unreliability of wind generation. This conclusion is at odds with Simshauser (2011) who commented that the back-up or “hidden costs” associated with wind generation are trivial. His comments were based on a case study of wind energy in South Australia where, in 2010 wind output exceeded 17 per cent of total generation. This percentage would now be substantially higher which could alter his conclusion.

2.6 Externalities associated with renewable energy

The viability of renewable energy projects, particularly household PV, reflects costs and benefits experienced by project developers, but does not include many related generation and network issues which developers currently do not experience (Simshauser, 2011; Lilley et al 2012). Hence they have not been modelled but they do have an economic impact that should not be overlooked, particularly when looking forward.

In the short-term these issues reflect related non-renewable energy costs of transitioning to a more carbon friendly environment but the pain is not evenly spread. For example coal-fired generation is likely to still have a place in the generation mix but its importance will be reduced. Non-renewable generation expansion will be curtailed and there will be short-term costs through capacity being less well utilised, resulting in capital costs not being fully recovered.

Issues associated with network costs in Australia, being distribution and transmission costs, are more complex. Distribution costs, associated with the carriage of electricity to households, will with increased household PV, be less well utilised with the owners being restricted in the extent to which cost recovery is possible. This reflects the fact that, in Australia, where there is a mix of privately and government owned distribution companies, the AER sets increases in network charges based on a range of factors (AER, 2015). As with generation, total cost recovery is not expected to be possible for several years when capacity becomes more closely aligned with demand. Households moving off grid, an increased likelihood given the decreasing cost of energy storage, will increase the concern of network companies being able to achieve full cost recovery.

Transmission costs in Australia will be impacted but to a lesser extent. As with distribution costs the AER sets increases in transmission charges which are paid for by two consumer groups; households through being on-charged by distribution companies, and large consumers who may also be on-charged by distribution companies or have a direct relationship with transmission companies, thereby making direct payments. With the ongoing development of large-scale renewable energy, transmission companies in Australia will become involved in a wider range of transmission projects that may provide a better portfolio mix. For example household PV will need greater support from backup generation, new large-scale solar and wind generation will require new transmission lines and the overall integration of renewable and non-renewable energy and storage requirement will require additional transmission support.

2.7 Relationship between renewable energy and carbon pricing schemes

The relationship between carbon pricing schemes, cap and trade schemes and renewable energy schemes is a key environmental and policy issue for several reasons. There is a need to ensure funding is well targetted, subsidies paid by consumers are as low as possible to achieve desired outcomes, schemes are compatible with each other, there is a clear relationship between emission targets and carbon price signals, and there is a clear understanding of the impact of changes in one type of scheme on other schemes. When making these comparisons, there are also less obvious benefits, particularly with renewable energy schemes such as energy security, local jobs and investment, but these are not examined in this thesis.

Authors that have examined the relationship between carbon pricing and renewable energy schemes include Lehmann and Gawal (2013) who, in a European context, disagreed with many scholars who suggested abolishing renewable energy schemes because they, the scholars, believed they did nothing for emission reductions and undermined the cost-effectiveness of the EU emissions trading scheme (ETS). Lehmann and Gawal (2013) believe their conclusions were based on narrow and unrealistic assumptions, valid only in a perfect world. It is Lehmann and Gawal (2013)'s view that where there were multiple policy objectives, such as a minimum percentage of renewable energy generation and a targeted level of GHG emission reductions, being common in many countries, then "a policy mix of the EU ETS and RES-E support schemes may be justified for a variety of reasons" (Lehmann and Gawal, 2013, p 604). In a follow-up paper Gawal et al (2014) concluded that "support for renewable energies (1) contributes to a more effective ETS-design and (2) may even increase the overall efficiency of climate and energy if other externalities and policy objectives besides climate protection are considered" (Gawal et al, 2014, p 175). Kalkull et al (2013) developed a model, with a German focus, to determine the best mix of carbon pricing and renewable energy policies, to avoid duplicating incentives.

Rio et al (2005) noted that in the EU it could be less costly to achieve emission reductions through Kyoto Protocol (CDM/JI) projects than by supporting new renewable energy projects. However this was noted as being less likely if the renewable energy project were undertaken overseas under the umbrella of a CDM/JI project as project costs are likely to be lower, while CDM/JI credits of CERs and ERUs would still be achieved. In this case domestic emission reduction benefits are reduced at the expense of overseas beneficiaries. Rio et al (2005) added that if there was instead a mandatory percentage of electricity that needed to be sourced from renewable energy then carbon-related projects would become a secondary consideration, in effect adding to the pool of renewables once the renewable energy percentage had been achieved.

A further variation was offered by Richstein et al (2015) who suggested that if renewable energy schemes became overly effective ("overshooting") then the emission cap in an ETS could be reduced. That is instead of altering the renewable energy target, thereby affecting investment certainty, the emission cap is lowered so that other carbon reduction methods, such as cap and trade, become the residual emissions reduction activity. Reducing the emissions cap reduces the carbon market price and hence reduces the viability of renewable energy projects helping to correct "overshooting".

The key connection between carbon pricing and renewable energy schemes is that they have a common objective of reducing GHG emissions but carbon pricing schemes may be ineffective if liable parties have little prospect of reducing emissions. Furthermore, if carbon pricing schemes are in a form of an emissions trading scheme there may be market price impacts of the like that recently occurred in the European Union. Luta (2014) commented on the oversupply of renewable allowances in the EU ETS noting that although the excess supply is continuously being wound back this has yet to arrest the dramatic price fall from EUR30/t CO2e in 2008, to EUR15/t CO2e from 2009 to 2011 and EUR$5/t CO2e to EUR8/t CO2e over the last two years, impacting the schemes effectiveness. Where renewable energy schemes run in parallel, there is the prospect that they could pick up the emissions target shortfall. KPMG (2014a)'s review of renewable energy schemes world-wide concluded that 117 of 138 countries had renewable energy targets and that 70 of the 138 countries had FITs or a similar premium payment. Most of the low income countries had renewable energy targets but few had FITs. The overall result highlights the substantial advancements that have been made world-wide in the field of renewable energy.

There is value in extending the analysis to try to determine whether Australia has an ideal mix of emission reduction schemes. Wilkins (2008) undertook research at a time when it appeared likely Australia would continue with an emissions trading scheme, commenting "If there were a broad-based perfectly functioning emissions trading scheme in Australia, there would be no need for any complementary policies. The trading scheme would deliver the most efficient outcome for Australia." (Wilkins, 2008, p 1). Wilkins added that there is a "rather disorganised set of programs" that should be transitioned from 62 to eight that, inter alia, should be more strategic and better aligned with the emissions trading scheme.

Australian Government Climate Change Authority. (2014) commented "It is likely a range of complimentary policies will continue to be necessary in Australia, and elsewhere, to deliver effective global action on climate change in the most cost-effective manner." (Australian Government Climate Change Authority, 2014, p 78).

2.8 Optimal integration of renewable energy, non-renewable energy and energy storage

The increasingly cost-competitive aspect of renewable energy begs the question of what, in future, will be the best mix of types of renewable energy, energy storage and conventional coal and gas-fired energy that will meet the objectives of supply reliability, emission reduction targets and least costs. This can be viewed at both the macro, national level or at the micro, household level which are both now discussed. The increasing number of articles written on this subject is useful but only in a generic sense as each country or individual household has its own particular features. For example relative costs are changing over time, reflecting in particular solar energy technology developments since 2008 and more recent energy storage developments having a large-scale production focus. Individuals are likely to be seeking solutions that differ from large-scale solutions, including seeking to be off-grid whereas large-scale solutions will reflect many factors such as carbon pricing, network pricing and the gradual reduction in network capacity and conventional power stations. In the case of individuals, consumption patterns can differ materially and price signals are not always readily available, often because technology associated with energy types is developing at different speeds. The initial discussion is at the broad, national level followed by emphasis on households, being more relevant to this thesis.

How renewable energy schemes and non-renewable schemes might work together, rather than let different types of schemes compete in the open market, has been attempted through regulation in the UK. The rationale is that the outcome may produce a more efficient market outcome because of the manner in which different schemes impact on the need for back up generation and the differing impacts on network costs. Gurkan and Langestraat (2014) viewed in a UK context, the requirement for generators to provide part of their output from renewable generation sources, receiving valuable certificates for doing so. They concluded that the scheme “cannot guarantee that the original obligation target is met, hence potentially resulting in more pollution” (Gurkan and Langestraat, 2014, p 85).

In a New Zealand context, of substantial hydro storage Mason et al (2013) concluded that security of supply over a six year period could be achieved with 100% renewables being “49% hydro, 23% wind, 13% geothermal, 14% pumped hydro storage peaking plant, 1% wood thermal plus biogas generation” (Mason et al, 2013, p 332). They suggested that peak demand could initially be met through 10% gas turbines to be eventually be replaced by pump hydro energy storage.

At the household level there has been much research recently relating to the development of models to find the optimal mix of solar/wind, and battery storage for given load profiles. Examples include Zheng et al (2014) who related electricity usage options to levels of battery storage and Stenzel et al (2015) who determined optimal generation designs for various mixes of load profiles and battery storage systems. A model using levelised cost of energy storage (LCOES) was developed by Parra et al (2015), in a UK case study, to show that the LCOES was much lower when determined on a 100-home community basis rather than for a single home. This result may be important when options are considered at the time battery storage becomes economic.

Ekren and Ekren (2010) developed a model to optimize the size of a PV/wind integrated hybrid energy system with battery storage. They noted this was ideal in remote locations "where the grid cannot penetrate and there is no other source of energy" (Ekren and Ekren, 2010, p 592). The model used historically derived distributions of solar radiation, wind speed and electricity consumption that converged at the 127th iteration to produce the optimum size of a PV/wind hybrid energy conversion system with battery storage.

Taha et al (2014) proposed the concept of renewable energy producers receiving a Quasi-Feed-in-Tariff (QFIT) which reflected market circumstances of grid, demand and energy price fluctuations. In simple terms the QFIT was designed to encourage renewable energy to produce when electricity prices were high, thereby reducing the need for peaking generation. This concept is great in theory but has the practical limitation in that substantial data and systems will be required as well as access to wholesale market prices such that the costs may outweigh the benefits. Fast developing technologies and greater economies of scale in the future suggest that eventually such "integration" models may be economic for use by households, world-wide. This may occur in the very near future given the comment by Naumann et al (2015):

> Using this model, we derive a clear picture of system profitability with dependence to all major influencing parameters. Applying the baseline aging characteristic and given the German market price trends, system profitability is expected to be in the very near future (Naumann et al, 2015, p 37)

Chapter 3 Climate change mitigation issues

Summary

Chapter 3 provides a perspective of the focus of this thesis by examining the reality of climate change as a major global problem, followed by a discussion of the different types of policy initiatives used world-wide to reduce GHG emissions. The focus of the chapter then narrows to an analysis of renewable energy schemes world-wide. The analysis is not in-depth and is only meant to provide an indication of developments world-wide to help put schemes adopted in Australia into some perspective. As with the thesis as a whole the focus is on schemes with financial incentives directly targeting emission reductions, rather than schemes relating to, for example, energy efficiency and energy conservation.

3.1 Climate Change Reality and the need for government involvement

Environmental issues affect society as a whole. It follows that everyone should pay for receiving the benefits of climate change action, but not everyone believes there is a climate change issue and so not everyone is willing to pay for action to be taken. Given that subsidies or incentives are paid either by government or electricity consumers, in effect everyone does pay so that such concerns have no practical way of being addressed. It is not surprising that there is no natural market-related economic outcome that addresses this issue and hence there are some “free riders”, or “partial free riders” but it is most likely free riders will eventuate whatever approach is adopted, otherwise no action will be taken and everyone is worse off, a typical moral hazard situation. Hence there is a need for government action in the form of subsidies or incentives to support reducing GHG emissions, reflected in the views of IEA (2012) who stated “incentives are justified to compensate for market failures” (IEA, 2012, p 11). The approach, world-wide, has been to focus on two types of schemes, being schemes that directly target emitters and those that have as an outcome emission reductions, such as renewable energy schemes (Ciarreta et al, 2014), the latter being the prime focus of this thesis.

3.2 Drivers of climate change action

The drivers of climate action stem initially from the realization that GHG emissions are harming the climate, followed by emission reduction targets (set either under international agreements, on a country by country basis or regions within countries) and consequent policy instruments considered necessary to achieve emission reduction targets. This gives rise to two challenges being the appropriate level of emission reductions and how best to achieve these reductions.

Increasing progress is continually being made world-wide to achieve emission reductions with Roelfsema et al (2014) concluding:

> Domestic policies of India, China and Russia are projected to lead to lower emission levels than the pledged levels. Australia's and the EU's nationally legally binding policy framework is likely to deliver their unconditional pledges, but not the conditional ones. The situation is rather unclear for Japan, South Korea, Brazil and Indonesia. We project that policies of Canada and the USA will reduce 2020 emission levels, but additional policies are probably needed to deliver their pledges in full. (Roelfsema et al, 2014, p 781)

3.3 Means of reducing GHG emissions – quantity and price schemes

The focus of this thesis is on renewable energy schemes and their cost-effectiveness in reducing GHG emissions but these schemes cannot be viewed in isolation from other emission reduction schemes for a number of reasons. These include the possibility of synergies, whereby renewable energy schemes and other schemes become more effective because of the existence of the others' scheme. Alternatively there is the possibility of duplication or conflicting impacts, such that other schemes become less effective, or even redundant. It would be ideal to find some combination of different types of schemes that result in an overall improvement in the cost efficiency of achieving emission reduction targets. As discussed in Section 2.7 this is a substantial task for various reasons but particularly because different schemes have different objectives and circumstances differ between countries.

In broad terms there are two types of emission reduction schemes, being "quantity" schemes having volume targets, such as renewable energy schemes where price is an outcome, and "price" schemes where prices are set, such as a carbon price, and volumes (of reduced emissions) are outcomes (Kesicki, 2011). Australia's recent Emissions Reduction Fund and Direct Action Plan (DAP) is a mix of these, but closer to a "price" scheme. A confidential benchmark price is set and bids (quantity and price) are accepted up to this price, a form of "closed" auction.

Although renewable energy schemes are "quantity" schemes they have a "price" scheme component as noted by Mananteau et al (2003):

> …it becomes crucial to take a look at the relative efficiency of the different schemes used. Such schemes may focus on quantities-defining national targets and setting up bidding systems, or quota systems providing for green certificate trading –, or they may focus on prices – feed-in tariffs. (Mananteau et al, 2003, p 799)

Part of the scheme distinction also involves whether schemes require funding or whether they are revenue generators. This distinction was noted at least as early as 1960 when Coase (1960) questioned how pricing should be applied in the case of "harmful externalities", asking should the creator be taxed or harmed parties instead compensated?

There are also schemes that have both price and quantity objectives such as "cap and trade" (CAT) schemes, also known as emissions trading schemes (ETS) having quantity targets with permits provided at prices either set by government or through an auction process. CAT schemes are treated as a hybrid or third option. Even schemes which appear to be price or quantity schemes have an element of the other. For example in Australia FITs, which are basically price schemes, often have state-determined quantity limits, and quantity schemes such as renewable energy schemes have price limits. Small-scale renewable energy schemes create STCs and large-scale renewable energy schemes create LGCs, each of these having a price cap reflective of the penalty price paid by electricity retailers in not being able to secure legislated minimum quantities, being (tax-adjusted (AU$57.14/STC and AU$92.86/LGC).

3.4 Baseline issues associated with emission reduction schemes

Quantity based schemes have challenges of establishing appropriate baselines, either in terms of emission levels or renewable energy output levels, and being able to effectively measure progress against these baselines. This is less of an issue with renewable energy schemes as new projects are easily identified, although there can be issues associated with determining the extent to which additional output from existing renewable energy schemes is subsidy driven.

An emissions benchmark level is set (or agreed to) having the effect that there is no penalty if emissions are reduced to the base level. A negative aspect of such schemes is that no extra penalty applies if emissions exceed the "business as usual" emissions level. If emissions are reduced below the benchmark level there is the likelihood, depending on the scheme, that emission credits can be created and on-sold, being important in ensuring emission reduction incentives are not limited. This could create an emissions "band" only within which incentives or penalties have meaningful effect, which ideally should be avoided. It is the setting of emissions baselines which is the most contentious issue associated with schemes having a price on carbon.

The problem is that this requires detailed, and often subjective, analysis to determine realistic emission reduction levels. Chomitz (1998) commented:

> Baseline determination unavoidably has a judgmental component. This means that baseline determination depends not just on methodology, but on a set of institutions that keep the

> methodology's application reasonable and honest. Overly lax baselines will threaten the system's credibility and usefulness, and shift rents from high quality providers to low quality providers of offsets. Overly stringent baselines will discourage valid projects and drive up project costs. (Chomitz, 1998, p i)

Baseline concerns were also expressed by MacGill et al (2006), and Fischer (2005) in regard to the United Nation's Clean Development Mechanism, noting that use of any of the three choices of (1) historical emissions, (2) expected emissions and (3) an industry average could either encourage or discourage project participation if participants expected outcomes different from those forecast (Fischer, 2005, p 1821). This gives rise to the need to contemplate a pricing scheme that penalises all emissions, thereby reducing the need for subjective analysis. As all emissions would be affected there would remain an incentive for all emission producers to reduce emissions. The downside is that parties having the greatest potential to reduce emissions would have much lower incentive levels and may not feel sufficiently rewarded to take significant reduction level action. This could be overcome by having a two-step incentive regime whereby incentives were higher for the first, say 5 percent of emission reductions.

It would appear that Jones (2010) had baseline concerns in mind when suggesting that there should be an international price on all emissions thereby eliminating the need for determining emission benchmarks. Jones (2010) concluded:

> An international carbon fee would place an equal burden (in terms of dollars per tonne of emitted carbon dioxide) based on easily- measured fuel quantities on all nations. It would embrace the great spirit of simplicity. The fee scheme would not require estimates of baseline emissions in countries where the data to determine such baselines are hard to find; nor would it require speculation on future business-as-usual emission scenarios. Nor would a uniform fee necessitate classifying nations according to income level, human development indices, or other measures. (Jones, 2010, p 249)

Jones did however recognise that some issues would still need to be resolved including the fee level, the emission sources to be included, possible perverse incentives and concessions needed to ensure the scheme is acceptable to all nations. It is possible for these reasons, particularly the loss of sovereignty, that this idea has not had great appeal.

3.5 Cap and trade schemes

This section examines cap and trade (CAT) schemes to better understand their effectiveness and limitations. The general concept is that GHG emitting companies are incentivised to reduce their emissions by a given amount, normally to reach a baseline amount, which is reduced each year, being related to the overall level of national emissions reduction targets. Companies may be assigned a level of permits that can be acquitted as compensation for emissions and these may be provided freely or at a price which could possibly be set at auction Ideally the incentives and penalties involved should ensure national emission reduction targets are met and permits are traded in a transparent manner such that there is a traded price thereby providing a market price on carbon.

CAT schemes have similarities with renewable energy schemes in that a baseline is created but with renewable energy schemes the baseline only has the purpose of rewarding parties which increase production above this baseline. GHG emissions are then reduced either by directly targeting levels of emissions, as with CAT schemes, or through encouraging renewable energy, designed to replace more carbon intensive types of generation (Brohe et al, 2009).

Realistic benchmarks are important because a party which is easily able to meet its emission reduction target could further reduce its emissions but may not have an incentive to do so. Permits are generally only allocated to emitters making it difficult for other parties to be actively involved in permit trading. This could be partly overcome through the inclusion of an auction system allowing permits to be purchased by any party. The benefit of allowing non-emitters to also access permits is to provide increased trading opportunities and hence greater choices for emitters to manage their permit shortfall positions.

The volume of permits made available is typically set below emitters' forecast emission levels, at a level considered the "benchmark", to provide the incentive for emitters to reduce their emission levels to that of the benchmark thereby avoiding penalties associated with a permit shortfall. This is a fundamental principle of CAT schemes (Bushnell and Chen, 2009; Judson, Matthew and Robert, 2009).

The extent to which permits should be provided freely, auctioned or only a portion being provided free was examined by Liu et al (2012) and Goulder et al (2010), the latter, in a USA context suggesting that no more than 15% of permits should be freely allocated being sufficient to "prevent profit losses in the most vulnerable U.S. industries" (Goulder et al, 2010, p161).

McKibbin et al (2014) noted that with CAT schemes it is the level of GHG emission reductions that are targeted with the carbon price set by market forces, whereas with a carbon price (or tax) the level of GHG emission reductions is determined by market forces but the carbon price is known, being set in advance. They argue that there are enormous risks associated with an emissions only target scheme and that there should also be carbon price collars, providing benefits of easing countries into emission reduction schemes and providing price transparency being useful for inter-country comparisons. Wood and Jotxo (2011) added that price floors could be created through "government commitments to buy back permits, a reserve price at auction, or an extra fee or tax on acquittal of emission permits" (Wood and Jotxo, 2011, p 1746) which could be complemented with price caps. They thought the fee idea was likely to be most favoured as it provided government revenue.

Repetto (2013) argued, in a USA context, that a CAT scheme is preferable to a carbon tax as it is more consistent with existing and overseas policies and provides more assurance that greenhouse gas emissions would decline sufficiently to avoid catastrophic damages from climate change. His preference was for government to issue permits to the current pollution levels and to then reduce the allocation by 3 percent each year. Firms that had low abatement costs could sell unneeded permits to firms whose abatement options are more expensive' who benefit by acquitting permits costing them less than the penalty for non-acquittal. Firms with low abatement costs would then continue to reduce levels of emissions. Avi-Yonah and Uhlmann (2009) instead argued that climate change action is an urgent issue, supporting the speed of implementing a carbon tax, rather than a CAT scheme taking years to develop and implement and having enforcement imposing difficulties.

One of the most comprehensive evaluations of CAT and carbon tax policies was undertaken by He et al (2012) using seven criteria (emissions price, emissions levels, renewable energy portfolios, total generation, generation and grid owner profits, economic welfare and emissions-adjusted economic welfare) highlighting the fact that CAT and carbon tax policies impact a wide range of participants and environmental issues, which is often overlooked.

Feijoo and Das (2014) developed a model that helps determine the optimal mix of generation to achieve a particular level of emission reductions. They also discuss the key CAT aspects of whether permits should be free or auctioned, how the limit should be reduced over time, the possibility of banking and penalties for permit shortfalls.

Cheng and Lai (2011) expressed concern that the financial burden on high polluters could cause them to exert political pressure to reduce pollution restrictions thereby causing even higher pollution. This appears to be an extreme comment but it does have similarities with the extent to which many Australian industries (Emissions-Intensive Trade-Exposed Activities, discussed in Section 7.4) which are exempt payment of renewable energy charges.

Bode and Michaelowa (2001) referred to "investment additionality" whereby incentives might be provided to projects that were going to be undertaken in any event. In a modelled example they note that "investors can have the incentive to invest at unfavourable sites, since the disadvantages from the reduced yield of energy can be more than offset by the revenues from the sale of the additional reduction units" (Bode and Michaelowa, 2001, p 29). This has similarities with Australia's renewable energy scheme whereby companies are rewarded for *growth* in renewable energy output. Where plant is already in existence, and therefore a sunk cost, increased output incurs only the marginal cost of production, so that output *growth* may occur without the need for subsidies such as LGCs.

Many other papers focus on how GHG reduction schemes could be structured for optimal results. Fischer and Newell (2005, p 142), in an American context, commented that optimal policy in achieving reductions has a ranking of (1) emissions price, (2) emissions performance standard, (3) fossil power tax, (4) renewable share requirement, (5) renewable subsidy and (6) R & D subsidy.

3.6 Price-based schemes

This section summarises world-wide GHG reduction schemes where a price is put on carbon either directly or through a market mechanism. The schemes examined do not target particular types of projects, thereby assisting in making international comparisons, and providing the possibility of linking schemes on an international basis.

Emission reduction schemes have been in existence since the mid 1990s with the situation in early 2014 being:

> About 40 national and over 20 sub-national jurisdictions are putting a price on carbon. Together these carbon pricing instruments cover almost 6 giga t CO_2e or about 12% of the annual global GHG emission. (World Bank Group, 2014, p 14).

As commented by World Bank Group (2014) it is a matter of two steps forward and one step back. Eight new carbon markets, California, Quebec, Kazakstan, and five Chinese regions commenced in 2013, but Australia repealed its carbon price and Japan, New Zealand and Russia pulled out of the second commitment period of the Kyoto Protocol. Regarding the first three countries, Senator the Hon Chris Evans, then Australia's acting Minister for Climate Change and Energy Efficiency announced on 1 January 2013 that new emissions trading schemes had commenced in California, Quebec, and Kazakhstan as well as Croatia through its entry to the European Union. He added they join 33 countries covering a population of more than 540 million people pricing carbon via national emissions trading schemes. Countries included the 27 member nations of the European Union, Norway, Switzerland, Australia and New Zealand. Later this year China – Australia's largest trading partner – was expected to roll out pilot emissions trading schemes in a number of its provinces and major cities.

Senator Evans commented further on schemes in the first four countries:

> The state of California has commenced a cap and trade program. An inaugural auction was held in November 2012, with over 28 million carbon units purchased. From 2013-14, the scheme will cover emissions from the electricity generation and industry sectors, representing around 35 per cent of the state's greenhouse gas emissions (approximately 160 million metric tons, or MMT). From 2015onwards, around 85 per cent (approximately 395 MMT) of the state's emissions will be covered and distributors of transportation fuel and natural gas will become liable (Evans, 2013, p 20).

Senator Evans added that Quebec, Kazakhastan and Croatia had introduced Emissions Trading Schemes and that Croatia had become "the 31st country to join the world's biggest carbon market after the 27 EU member states, Iceland, Liechtenstein and Norway". (Evans, 2013)

3.6.1 *United Nations emission reduction commitments*

On an international basis, targets have been proposed and agreed to by United Nations members. The first major, but not binding agreement, was the United Nations Framework Convention on Climate Change (UNFCCC) opened for signature in 1992 having been signed by 157 nations as at December 1992 (Edmonds et al, 1995). Co-ordinated action first occurred in 1998 when 55 nations signed up to the UNFCCC ("Annex B" parties) with 37 agreeing to reduce their GHG emissions by an average of at least 5% on 1990 levels between 2008 and 2012, with Australia's target being not to exceed an increase of 8% which it subsequently met. Countries, not being the same as those in the original group, subsequently agreed to a second non-binding commitment reduction over the period to 2020. The two main means by which Annex B parties can meet their emission reduction commitments are the Clean Development Mechanism (CDM) whereby parties can purchase certified emission reduction (CER) units, relating to emission reduction projects, from less developed countries, and the Joint Implementations (JIs) whereby emission reduction units (ERUs) are created by an Annex B party undertaking a carbon emission activity, which can be sold to another Annex B party (Rio et al, 2005; Lazarowicz, 2009).

The different means by which EU parties can meet their emission reduction obligations has resulted in some concerns, relating to, for example, effectiveness and evidential credibility. For example Woerdman (2000) concluded that, for many reasons JIs and CDMs are preferable as international emission trading (IET) could possibly involve “fake” emissions.

Since the 1997 Kyoto meeting there have been 21 annual meetings of the Conference of Parties (COP), the most recent being in Paris in 2015, resulting in mixed progress. Part of the problem is that to reach agreement requires nations to have a common view on the level and timing of emission reductions so that although most nations agree in principle they do not agree on the detail proposed. However many nations, because they agree in principle, have taken action of their own, often on a regional basis to limit GHG emissions.

3.6.2 *European Union emission reduction schemes*

The most active emission trading takes place in the European Union (EU), where carbon trading began in January 2005 (Austin, 2007) through the European Climate Exchange (ECX) where futures contracts are cleared through the Intercontinental Exchange (ICE) (Ellerman, Convery and Perthius, 2010). The market based reference price, for settling derivative contracts involves a mix of European Union Allowances (EUAs), being permits allocated to EU ETS participants and Certified Emissions Allowances (CERs), being credits issued to participants without binding targets so that they can trade with participants with binding targets (Austin, 2007). Austin (2007) mentioned the two market phases of 2005 to 2008 and 2008 to 2012, with the former period being when the market was oversupplied with prices dropping and the second when supply was to be reduced to correct this. Since then however prices have remained comparatively low, being an issue to the extent that carbon trading schemes are internationally linked.

There are various papers written questioning the scheme, for example in regard to “leakages” (Bushnell and Chen, 2009) and also Marshinski et al (2012) who concluded that linking the European Emissions Trading System to other schemes, without full emissions caps, could increase total global emissions. On the positive side, the scheme has some deliberate “leakages” in the form of the creation of CERs providing assistance to less developed countries as mentioned above.

3.6.3 *Emission reduction schemes world-wide*

Differences in political leaders' environmental views have impacted on the introduction of emission trading schemes both at the national and regional level in many countries. In addition the views of the people may not be the same as their leaders as has occurred in Greece. Tsantopoulos et al (2014) commented that more than 50% of the Greek public supported PV, for environmental, financial and social considerations whereas the government was promoting legislation that would disallow new applications for household PV.

Many non-European countries have GHG emission reduction schemes either applying nationally or on a regional basis (Talberg and Swoboda, 2013). World Bank President Jim Yong Kim summed up the situation in September 2014 by commenting:

> Today we are announcing that 73 national and 11 regional governments and over one thousand companies and investors support putting a price on carbon. Together, these government supporters represent 52 percent of global GDP, 54 percent of global greenhouse gas emissions, and almost half the world's population. The supporters include emitters like China, Russia and the European Union, and growing economies like Indonesia, Mexico, and South Africa. Many already have carbon pricing in place or are preparing to implement it. Others, including the Philippines and many small island developing states support carbon pricing because they know that without such action, climate change will have devastating impacts on their populations and on their economies. Companies such as LG Electronics, National Grid and Westpac have already integrated a "shadow" price on carbon into their business strategies to improve decision-making for the future. They know that this will help avoid risks and find opportunities that can increase energy and resource efficiency, reduce CO_2 emissions, and give them a competitive edge. (World Bank, 2014, p 1)

In New Zealand, an Emissions Trading Scheme was enacted in 2008 requiring emitters to surrender one emission unit, provided free by the government, for every two tonnes of carbon dioxide reported, or buy New Zealand units from the government for NZ$25 per unit. The number of free units issued is set at a level to encourage emission reductions but is not seen as a CAT scheme (Bertram and Terry, 2010).

Regional schemes exist in many countries, including USA, with a California focus (C2ES, 2012) and China, currently with 18% coverage (Lo, 2012) of regions with schemes in place to reduce GHG emissions (Grubb, 2012; Lo, 2013). Canada has regional reduction schemes in Quebec and

British Columbia (Core, 2011). Aldy and Stavins (2012) commented that "Greenhouse gas cap-and-trade systems are in place or under development in the European Union, Australia, Japan, Korea, New Zealand, California (USA), and several Canadian provinces" (Aldy and Stavis, 2012, P 1044). In broad terms there is an increase in the number of schemes in place or about to be introduced.

The USA extended trading in established exchange traded contracts, such as oil and corn, to include Carbon Financial Instruments (CFIs) traded on the Chicago Climate Exchange (CCE), being financial contracts with the right to emit 100 tonnes of CO2e. This is a voluntary system but by joining firms legally commit to reducing their emissions. The CFIs allow firms to emit to levels no greater than 6% below their 2010 baseline levels. Firms achieving better than 6% reductions can sell their excess CFIs to firms that have not achieved this minimum reduction level. CFIs can also be generated by offsetters (forestry, renewable energy, landfill methane for example). As at 2011 500 firms had joined (Sabbaghi and Sabbaghi, 2011). Shortly thereafter the CCE lasted was purchased by Europe's Intercontinental Exchange and then closed through lack of activity. (www.CO2offsetresearch.org/policy/ccx.html)

3.7 Bi-lateral and multi-lateral emission reduction agreements

Countries (and regions) have, over time, taken closer notice of the development of schemes in other, particularly neighbouring, countries, for various reasons, including fairness, so that some countries are not providing harsher measures than their trading partners, which could negatively impact on trade outcomes. In the USA these issues became a prime focus in Peter Orszag's testimony to the US House of Representatives in 2008, in which he suggested, to retain competitiveness, American export and import industries could be rewarded or penalised depending on the comparative impact of carbon reduction mechanisms in the USA and overseas trading countries (Orszag, 2008). He added that lessons could be learnt of the sorts of incentives that are effective in other countries and the possibility that domestic credits could be used in other countries to reduce their GHG emission obligations. This helps to ensures parties to successful schemes continue to take action to reduce emissions following their targets being met. This is not dissimilar to the UK JI scheme mentioned in Section 3.6.1.

Burniaux, Chateau et al (2009) suggested an integrated approach in determining action necessary to reduce GHG emissions, including phasing out fossil fuels, linking regional carbon schemes and, in particular, addressing deforestation. Ackerman, Stanton and Bueno (2010) concluded that to achieve optimal GHG reductions it would be necessary for a substantial, but possibly politically unacceptable, flow of capital from rich to poor nations to occur. Chichilnisky and

Block (2000) expressed similar views, questioning why rich countries should financially contribute if they are not big emitters. Houser, Bradley, et al (2008) questioned how strict internal emissions restrictions should be, and by industry, when other countries have a wide range of less restrictive policies. Vob (2007) had a similar concern, cautioning that consideration needed to be given to the possible negative impact of an emissions trading scheme on domestic policies and goals. In New Zealand these issues seem to be less of an issue with MFE (2010) noting that the New Zealand government is not overly concerned with leakage, recognising and accepting that industries overseas could benefit from New Zealand’s emission regulations.

There is however not uniform agreement on the benefits of linking schemes. Marshinki et al (2012) noted the importance of all participating countries in cross-border trading having CAT schemes in place and developed a model suggesting that if this is not the case the overall outcome could be no effective benefit with overall emissions levels possibly being higher. Cian and Tavoni (2012) through development of a model, argued that restrictions on international trading of emission permits could limit technology advancements.

The fundamental problem with most of these questions is that these views could be used to argue for no action when even the authors involved do not question the need for some action. A more positive comment was made by Jaffe, Ranson and Stavins (2009) who suggested that when linkable trading permits are traded between countries, some prices will increase and some will decline, but the overall effect will be a reduction in emissions.

In Australia the intention had been to enable credits to be used by another country to help meet emission commitments, on 1 July 2015 (Clean Energy Regulator, 2012b). The current Coalition government does not, however appear enthused by such ideas.

3.8 Global renewable energy schemes

Renewable energy schemes around the world are driven by incentives such as credits for units of renewable energy production, normally above a baseline, FITs for renewable electricity exported to the country’s grid, and grants to establish projects, all of which exist in Australia and are discussed in Chapter 2. This section takes a more global view examining world-wide renewable energy developments.

The wide range of world-wide renewable energy schemes and their rapid growth is discussed in Dusonchet and Telaretti (2015) and REN21 (2016). IEA (2016), which views world-wide trends in PV, noting that 2015 PV capacity increased by 50.7 GW, a 26.5% increase over 2014, with most of the growth occurring in China, Japan and USA.

An indication of increased funding for renewable energy projects world-wide, can be seen by comments made by Bloomberg (2014) that world-wide clean energy investment in the September 2014 quarter was US$55 billion, up 12% from the US$48.9 billion in the September 2013 quarter, Chinese solar investment rose to a new record of US$12.2 billion, with solar installations expected to “total 13-14GW in 2014, nearly a third of the world total” (Bloomberg, 2014, p 1) and that solar growth was also strong in Japan, with investment bounces also in Canada, France and India.

This growth continued in 2015 with average quarterly new investment reaching US$87 billion, although this dropped to an average US$58 billion in the first two quarters of 2016, due mainly to small-scale solar investment being down US$9 billion over the same period a year earlier (Bloomberg, 2016). As well as the simple economics of renewable energy there are also other benefits not often recognised. IRENA (2016) comments that “doubling the share of renewables in the energy mix by 2020 would increase global GDP by up to 1.1 percent, improve welfare by up to 3.7 percent and support over 24 million jobs in the sector” (IRENA, 2016, p 77). The International Energy Agency has provided forecasts to 2020 with the renewable energy share of generation expected to rise “from 22% in 2013 to over 26% in 2020” representing “more than today’s total combined demand of China, India and Brazil” (IEA, 2015, p 3)

Chapter 4 Australia's approach to reducing greenhouse gas emissions

Summary

Chapter 4 focuses on Australia's approach to reducing GHG emissions covering Australia's international obligations, the rapid growth in household PV in Australia and the underlying reasons. Finally, continuing with a household focus, demand-side management is examined noting how electricity consumption has declined coincident with the rise in real household electricity prices. These schemes are viewed in the context of relevance to the model developed and in Australia meeting its targeted emission reduction levels.

Key milestones have been 1998, when Australia signed the UNFCCC "Kyoto" protocol (to reduce GHG emissions) (section 3.6.1), followed by ratification in 2007, 2001 when the MRET scheme was introduced (Section 4.2), 2008 onwards when states introduced FITs (Section 5.6.2), 2011 when the MRET scheme was split into two schemes targeting small and large-scale renewable energy, 2011 when the Clean Energy Futures Plan was introduced which covered a range of issues but particularly the carbon price, and 2013 when the Direct Action Plan was introduced (Section 4.2). These are covered in the sections mentioned, to the level of detail considered appropriate to the focus of the thesis.

Australia's initial KYOTO commitment was to achieve emission levels not exceeding 108% of 1990 levels over the period 2008 to 2012, which it met and received credits for over-achievement. This was followed by a non-binding commitment to reduce emissions by at least 5% by 2020 compared with 2000 emission levels (Combet, 2012; United Nations, 1998). Neither of Australia's first (unconditional) 108% target not its subsequent (conditional) 95% target was seen as particularly onerous relative to those of other countries (Fraser, 2015).

At the most recent UNFCCC annual 21st Conference of Parties (COP21) meeting, in Paris in November 2015, Australia formally advised, in its Intended Nationally Determined Contribution (INDC) to a new Climate Change Agreement that it will "implement an economy-wide target to reduce greenhouse gas emissions by 26 to 28 per cent below 2005 levels by 2030" (www4.unfccc.int/submissions/INDC). On 5 October 2016 it was announced that the participating parties' agreement threshold had been reached resulting in the undertakings given by each participant taking effect 4 November 2016.

The thesis does not focus in any detail on schemes and incentives beyond those clearly identifiable with the focus of the thesis. Nevertheless there are a range of measures that have also been very effective in reducing emissions, including those included in the 2011 Clean Energy

Futures Plan such as assisting businesses in using more energy efficient technologies, improved housing design and construction, mandatory emission reduction standards for new light vehicles and farming related initiatives to reduce emissions and store carbon (Australian Government Department of Climate Change and Energy Efficiency, 2012b). In addition there are many examples contained in www.energyefficient.com.au/reports-papers relating to Australia's standards, labelling, smart appliances, insulation and energy efficient appliances.

4.1 Australia's targeted emission reductions

Australia committed to reducing its overall emissions to at least 5% below 2000 levels by 2020 as part of the suite of announcements in 2011. This target equates to reducing emissions from 565 million tonnes CO_2e (m t CO2e) in 2000 to 537 m t CO_2e in 2020 (Australian Government Department of Climate Change and Energy Efficiency, 2012a). Australia's GHG emissions in FY 2013 totalled 562.8 m t CO_2e (electricity contributing 193.1 m t CO_2e, or 34%). Australia's emissions reduction target for 2020 equates to 537 m t CO_2e, with 191 m t CO_2e targeted from electricity generation (Australian Government Department of Climate Change and Energy Efficiency, 2012a; Australian Government, Department of Environment, 2013). These figures show that electricity sector GHG emissions are targeted to decrease only marginally to 2020, partly due to the impact renewable energy has already had on GHG emission levels.

Australian Government, Department of Environment (2015a)[3] suggested the overall target to be achieved, as at March 2015, is a further reduction of 126 m t CO_2e by 2020 compared with current projections that would otherwise result in 656 m t CO_2e. These figures indicate rapidly increasing levels of GHG emissions on a business-as-usual basis, resulting in the need for substantial emission reductions. The business-as-usual assumptions however appear overly pessimistic, but the comment was added that the outcome of the DAP had not been included which was expected to have a substantial impact.

DAP auctions in 2015 contracted 93 m t CO_2e abatement, some of which is likely to be from the electricity sector, and is expected to achieve 431 m t CO_2e reductions between 2015 and 2020 (KPMG, 2014a). The DAP verification process, to be undertaken in 2016, will be very important in substantiating the accuracy of these figures. Even if substantiated there is the further issue of actual additionality, that is the extent to which some of the lowest cost bids may represent

[3] There is a small difference between Australian Government Department of Climate Change and Energy Efficiency (2012) figures showing the 20 year target decreasing from 565 to 537 m t CO_2 and Australian Government, Department of Environment (2015a) showing the target decreasing from 559 to 530 m t CO_2.

projects that would have taken place in any event (Burke, 2016). These figures highlight their importance of the DAP in Australia meeting its emission reduction target.

Australian Government, Department of Environment (2015a) show electricity sector emissions having increased by 5 m t CO_2e between FY 2000 and FY 2014, to reach 180 m t CO_2e, with an extra 21 m t CO_2e expected to FY 2020, reaching 201 m t CO_2e, exclusive of any abatement from the DAP. The figure of 201 m t CO_2e, as with total levels of missions, appears overly pessimistic. If these figures are realistic they suggest that the electricity sector needs to ensure that emissions do not increase by more than 11 m t CO_2e to achieve the target level of 191 m t CO_2e, or put another way electricity sector emissions need to be 10 m t CO_2e lower than those forecast.

Australia's emissions projections are being updated on a very frequent basis with Australian Government, Department of Environment (2015d) being the most recent update (December 2015) showing forecasts for total emissions at FY 2020 of 593 m t CO_2e, being 59 m t CO_2e (9%) below previous projection of 656 m t CO_2e. This is 12% above the required target level (of 530 m t CO_2e) but it is argued that the target will be met when additional DAP auction results are included. These figures show how quickly emission reduction progress is being made. Reasons for the latest forecast emissions reduction to 593 m t CO_2e are described as relating to adjustment to the LRET target, as well as "closures of high emitting coal-fired power stations and as a result of gas generation largely maintaining its share of generation after 30 June 2014" (Australian Government, Department of Environment, 2015d, p 4) all of which are included in thesis modelling. Electricity sector emissions are now forecast to reach 187 m t CO_2e by 2020, 4 m t CO_2e lower than previous projections because "abatement from the Emissions Reduction Fund (being the DAP) have been incorporated in projections for the first time" (Australian Government, Department of Environment, 2015d, p 4), being below the 191 m t CO_2e target, again highlighting the importance of the DAP scheme..

The emissions projections in this thesis relate only to electricity-related generation emissions and do not include DAP emissions. Hence they are marginally higher than published electricity emission reduction forecasts. In summary Australia appears to be on target to meet its emissions reduction target if the DAP scheme to FY 2020 is as effective as forecast. Modelling in this thesis suggests that the electricity sector will reduce emissions by 23.9 m t CO_2e between 2000 and 2020 (Table 7.7), providing a key contribution towards achieving this target.

4.2 Emission reduction schemes in Australia

In Australia there has been electricity-related action on two key fronts to reduce GHG emissions, having a price on carbon and having incentives to encourage renewable energy schemes. The former was the result of a compromise between the newly elected minority Gillard Labor government and the Green Party in 2010 to put a price on carbon, as preferred by the Green Party, prior to introducing an ETS (The Australian, 1 December 2010). Eventually, in FY 2013 and 2014 the Labor government imposed a price on carbon emissions by large emitters, including electricity generators, whose GHG emissions exceeded 25,000 tonnes pa. of carbon dioxide equivalent (AG, 2011). The price was set at AU$23/t CO_2e in the first year, and was intended to be increased at 2.5% pa in real terms over the next three years but this was terminated a year early when the Labor government was replaced by the Coalition government in 2013. Over the two years when the carbon price was in place, revenue of AU$13.5 billion was received by the government (Heath, 2014).

It had been intended, for a three year period from FY 2016 to FY 2018, that an ETS, also known as a CAT, scheme was to apply with a ceiling price set at AU$20/t CO_2e above the international price, increasing at 5% pa in real terms[4]. Acceptable for compliance were to be carbon permits, Australian Carbon Credit Units (ACCUs) and International units for up to 50% of a company's obligation (Westpac, 2012). In addition free permits were to be provided for a portion of these emissions (Carbon Market Institute, 2013). After 2018 the only variation was to be that Australian companies could sell (that is as well as buy) carbon permits overseas (Ashurst, 2012).

The Coalition government, on coming to office in 2013, terminated the carbon price scheme effective 1 July 2014 and introduced a Direct Action Plan (DAP) under the umbrella of the Emissions Reduction Fund (Australian Government, 2014). The scheme provided for parties to offer, in an auction system, the level of emission reductions they would target for a certain financial inducement with the lowest bids being accepted up to a total level of emission reductions. In this way reductions occur at the least cost (Montgomerey, 1972; Judson et al, 2009). Compared with the carbon price scheme which generated government revenue, the DAP scheme is budgeted to cost the government a maximum of AU$2.55 billion over a three year period commencing late 2015 (KPMG, 2014b, Australian Government, 2014).

Two DAP auction rounds have been held to date, the first in April 2015 resulting in 47.3 million tonnes of CO_2e abatement contracts being awarded at an average price of AU$13.95/tonne CO_2; and the second in November 2015 resulting in 45.5 million tonnes of CO_2 abatement contracts

[4] A floor price was earlier legislated but this was announced to be withdrawn on 28 August 2012

being awarded at an average price of AU$12.25/tonne CO_2e (www.CleanEnergyRegulator.gov.au). The next auction is to be held in April 2016. The average abatement cost of AU$13/tonne CO_2e compares favourably with other abatement cost experienced to date in Australia. The DAP has cost the government AU$1.2 billion to date in comparison with the earlier carbon pricing scheme that generated revenue of AU$13.5 billion over two years. The DAP could be an effective emissions reduction scheme but this will only be known following the DAP audits in 2016 when actual emission reductions are compared with contracted levels of abatement.

The Labor party's proposed ETS scheme would have required large emitters to purchase emission permits, providing the right to generate GHG emissions up to a specified "benchmark" level. Where emitters were able to achieve additional emission reductions they could sell any excess permits to parties who are unable to achieve emission reductions. This is the "trade" aspect of an ETS. The setting of the "benchmark" creates the "cap" giving rise to an ETS also being known as a CAT scheme.

The second type of schemes are "quantity" schemes, being schemes with a targeted level of renewable energy generation, such as renewable energy schemes, where the market sets the carbon price, or equivalent subsidy price. The two main political parties are generally close to agreement on "quantity" schemes. As background Australia implemented the world's first national Mandatory Renewable Energy Target (MRET) in 2001 (Kirsebom-Aronsen, 2013; Cludius et al, 2014) which encouraged renewable energy schemes by crediting each megawatt hour of renewable energy output above a base level of an average of 1994, 1995 and 1996 levels (Clean Energy Regulator, 2012a; MacGill et al, 2006) with a REC, later re-classified as either a large-scale generation certificate (LGC) or a small-scale technology certificate (STC). (Clean Energy Regulator, 2012a). The demand for RECs is created through electricity retailers having a legal obligation to purchase a proportion of their sales in the form of RECs. The MRET target was initially set at 9,500 GWh by 2010, then in 2009 increased to 45,000 GWh by 2020 (then constant to 2030). At the same time the MRET was renamed the renewable energy target (RET).

At both the Commonwealth and state levels it was considered desirable to provide further support for small-scale renewable energy, in particular household PV and household solar hot water systems. To achieve this, a REC multiplier was introduced (the "Solar Credits Program") providing for extra "deemed" RECs to be created (Renewable Energy (Electricity) Amendment Act 2010). The 45,000 GWh target was calculated to deliver approximately 20% of total electricity generated from renewable energy sources. On 1 January 2011 the 45,000 GWh target was split into the large-scale renewable energy target of 41,000 GWh and an implied small-scale renewable energy scheme target of 4,000 GWh (AEMC, 2013). The reason for this was:

> Higher than expected uptake of small-scale systems – provided with extra encouragement through the Solar Credits multiplier and state/territory feed-in tariffs – had created a large number of certificates, depressing prices and discouraging investment in large-scale projects. The division of the RET was designed to address this issue by creating separate incentives for large-scale energy projects (such as wind farms) and small-scale technologies (such as solar PV and solar water heaters), which no longer directly competed with one another under the RET scheme. (Australian Government Climate Change Authority, 2012, p 14)

If retailers are unable to purchase their annual liability levels of LGCs there is a shortfall penalty of AU$65/LGC and in the case of STCs there is a shortfall penalty of AU$40/STC. If shortfalls did occur retailers could not use the penalty charges as a cost to their businesses so in effect the costs of these shortfalls, in tax adjusted terms, at a 30% tax rate, was AU$92.86/LGC and AU$57.14/STC, which was recognised as the market price cap. There has continued to be bipartisan support for the scheme so it is likely the scheme will continue in some form (Kirsebom-Aronsen, 2013).

In 2014 there was an RET review resulting in the concept of the scheme being retained but in 2015, following the Coalition government being elected to power, it was argued that the reduction in overall energy demand meant that a 41,000 GWh LRET target would result in much more than a 20% level of renewable energy. Agreement was reached to reduce the LRET target to 33,000 GWh effective March 2016 (Australian Government, Department of Environment, 2015b). No changes were made to the SRES scheme which does not have a limit, although it earlier had an implied 4,000 GWh limit. The market viewed the outcome as still being a challenge, resulting in the LGC price quickly increasing from a little under AU$40/LGC to nearly AU$70/LGC between March 2015 and September 2015. (www.mercari.com.au). Unfortunately there was much uncertainty in 2014 and early 2015 about what the target could have been creating an environment not conducive to investors with the outcome being that renewable energy investors took some time to come back into the market (ShahNazari, 2014).

4.2.1 *Benefits and disadvantages of schemes used in Australia*

The two types of schemes have a range of favourable and less favourable aspects that are important to appreciate in considering emission reduction schemes in Australia in future. A price on carbon provides the clearest carbon price signal, being important in encouraging market participants to take action to reduce GHG emissions. Having a market carbon price is also useful in encouraging other schemes, such as carbon offset schemes, whereby approved parties are rewarded for achieving emission reductions through, for example, reducing landfill emissions or planting trees. The carbon offsets produced are then available for purchase by carbon liable parties (Australian Government, Department of Environment, 2010).

Renewable energy schemes instead involve long-term decision making with vastly different emission reduction results. An example is in the case of bagasse-fuelled renewable energy, a by-product of sugar refining, which receives the same incentives as solar systems although some emissions would have been created because the bagasse needs to be burnt to fire a boiler (to create steam to go through a turbine to create electricity). The emissions from a bagasse-fired plant are however very low according to Basu et al (2011) and have therefore been ignored.. Another view, promoted by Millis (2016) is that bagasse-fired generation has little harmful emissions because all the carbon emitted has been withdrawn from the air by the growing of cane giving zero net emissions. The validity of this view is dependent on whether sugar cane is only economic to harvest if supplementary revenue is generated from the electricity producing process. This is unlikely to be the case, although it could be valid in an additionality sense.

Not surprisingly different implications and consequences have resulted in no one particular scheme being favoured world-wide. Similarly there is no consensus view in Australia. In fact there is an opinion that Australia may need a mix of policies, with Climate Change Authority (2014) stating “It is likely a range of complimentary policies will continue to be necessary in Australia, and elsewhere, to deliver effective global action on climate change in the most cost-effective manner”. (Climate Change Authority, 2014, p 78)

In examining the choice of schemes a key issues is whether a particular scheme operates “in total” or “at the margin”, that is whether a scheme operates to benefit or penalise (a) some or all participants and (b) at all levels of activity or only activities “at the margin”.. In effect there is a trade-off between the simplicity of a scheme capturing all participants and all activities, and therefore not having to determine a benchmark level, having an element of subjectivity, and a scheme that targets activities that could be affected by a price on carbon. The former is effective but not efficient whereas the latter is possibly efficient and effective but only to the extent that meaningful benchmarks have been set.

In an Australian an example of (a) is the “in total” approach that occurred in FY 2013 and FY 2014 with a carbon pricing scheme introduced which targeted large emitters (of over 25,000 tonnes t CO_2e pa) including electricity generators, who were required to pay a price for all emissions, even though in many cases there was little capability of reducing levels of emissions. In the case of electricity generators the result was some (emission beneficial) switching between black and brown coal-fired generation and between coal and gas-fired generation. In the case of large emitters, many incurred an unavoidable cost impost but there were some benefits in a price signal being created that could have encouraged new entrants, but uncertainty of this policy's future is likely to have discouraged any material action.

In the case of renewable energy projects, schemes are efficient because an "at the margin" approach is applied. That is only new projects or additional output to existing projects above a 1999 output level are able to access renewable energy credits. Nevertheless there are baseline issues to be considered which, in Australia's case, are well documented in MacGill et al (2006) in regard to the various Commonwealth and state emission reduction schemes adopted in Australia.

There are also second order effects that connect these schemes. A price on carbon if passed on to consumers in higher electricity prices, improves the revenue potential, and therefore viability, of renewable energy projects. By reducing carbon emissions, renewable energy schemes contribute to the overall level of emission reductions that may be sought nationally. Hence the more the success of renewable energy schemes, the less punitive do carbon reduction schemes have to be to ensure the overall level of targeted emissions is achieved. A good example of this is occurring in Australia at present where renewable energy schemes have been very successful in reducing GHG emissions to the extent that the DAP scheme may need only to be partially successful for Australia to meet its 2020 electricity-related emission reduction targets.

4.3 Features of rapid growth in Australian household PV

The key features of the rapid growth in Australia's household PV have been the substantial decline in solar panel costs, attractive FITs and the multiplier applied to STCs. PV panel costs decreased by over 50% between 2008 and 2012 and have remained stable since then despite the much weaker Australian dollar. FITs for new installations rose to a peak of AU57c/kWh in 2012 and now represent only the exported value to retailers, of about AU8c/kWh, but it is new panel costs that have resulted in the demand for PV not declining to the extent expected (Clean Energy Council, 2013). Nevertheless at some stage a saturation level will be reached whereby the non-PV household group will take an increasing level of enticement to be attracted to PV. In late 2013 the Australian states of Queensland and South Australia penetration rates had increased to 22% and 25% respectively with a nation-wide average of 14% (Parkinson, 2013), increasing to 29% and 30% respectively with a nation-wide average of 20% in 2016 (APVI, 2016).

The rapid growth in PV was also caused by additional “deemed” STCs that could be created, having a multiple of five for FY 2010, intended to be reduced by one each year to reach unity by FY 2014. Recognition of the rapid PV growth caused the scheme to be terminated six months early on 1 January 2013 (Watt et al, 2012; NSW Government, 2011). The unexpectedly high growth in household PV prompted speculation on how attractive FITs could be altered including the breaking of FIT contracts. This was attempted on a retrospective basis by the NSW government in May 2011 but then withdrawn due to public backlash (Sydney Morning Herald, 2011). The only other means for this to happen is when households with PV shift house, causing FITs to terminate, with the later impact estimated to be in the 3% to 4% pa range (Parkinson, 2013).

4.4 Demand-side management

Australia has a range of energy efficiency schemes that have preceded the price-related GHG emission schemes that are the focus of this thesis. These schemes are not examined in detail and are not modelled except for the impact of high retail electricity prices on electricity demand. These schemes include mandatory labelling of appliances introduced in 1992, estimated to have reduced emissions by an average 600 thousand t CO2 over the period 1992 to 2000 (Holt and Harringtong, 2003), minimum mandatory energy efficiency performance standards (MEPS), also introduced in 1992 initially for refrigerators and freezers (Saddle, 2014), and a range of measures as part of the 2011 Clean Energy Futures plan, also discussed in Summary to Chapter 4. Saddler (2014) estimated that between 2006 and 2013 building, appliance and equipment measures had reduced electricity demand by 10.5 TWh, or 28% of total estimated electricity demand.

Energy conservation took a sharper focus in Australia from 2008 onwards due largely to sustained increases in retail electricity prices. Australian Government, Department of Industry and Science (2015b) commented that Australians have enjoyed historically low electricity prices, but over the period from 2008 - 2014 prices increased by over 80 percent, and this is significantly more than inflation. Expenditure on energy was 5 per cent of average gross weekly household income in 2012, ranging from “almost ten per cent for low income households to as little as three per cent for high income households” (Australian Bureau of Statistics, 2013) and likely to be higher since then due to real price increases. As mentioned in previous chapters households have sought new opportunities to reduce these costs, including installing PV for electricity, solar water heating and more efficient energy appliances. This is in addition to the increasing realisation and appreciation that by pursuing energy conservation not only were households achieving cost savings but there were also environmental benefits. The largest impact on retail electricity prices over the 2008 to 2014 period was the two year (FY2013 and FY 2014) price on carbon causing households to further conserve their use of electricity.

On a broader scale further gains could be made if households were able to aggregate contracted electricity reductions and be paid for this either in the form of carbon offsets or through bidding reductions into an auction such as Australia's DAP or bidding into the National Electricity Market (NEM) as a form of generation. Advances in areas such as use of Time of Use Meters, and appropriate price signals, and purchasing of energy efficiency are now explored in further detail.

4.4.1 *Factors that influence household electricity consumption behaviour*

As a general rule, electricity is viewed as an essential commodity with consumers using electricity when it is needed regardless of price, creating a very low price-demand elasticity. The approach, leading to quantitative analysis, has been to examine changes that have occurred or could occur to enable Australian households to become increasingly demand responsive to electricity price rises, to analyse international price elasticities of demand and to determine price elasticities of demand that have recently occurred in Australia. Developments that would be of assistance in encouraging demand-side management in Australia are now examined.

Public Attitudes

The public attitude towards environmental conservation has, in the last five to ten years, become more noticeable in line with increasing belief in the reality of climate warming. Households are more likely to take action, from a price signal, to reduce electricity consumption when such action is seen to provide benefits beyond those affecting their personal financial positions. The outcome is likely to have increased the sensitivity of electricity consumption to price changes in more recent years.

Information that assists in electricity demand conservation

Provision of easily understandable information on the electricity usage of appliances assists households in taking short-term action in how they use appliances as well as long-term action in their decision-making to purchase new appliances. In the past such information was general not available . Selling competitive pressures have helped cause this change but only in the knowledge that the public had such an interest.

Technology that assists in electricity demand conservation

Meters, commonly known as “smart” meters, that provide real time information on electricity usage of different appliances is information that was not readily available in the past. However “smart” meters come at a cost, varying from AU$100 to AU$1,000 so households need to be aware of the associated costs and benefits.

The cheapest form of smart meter is a “time of use” (TOU) meter that measures electricity consumption on a half-hour basis. Many states in Australia have or are contemplating rolling out smart meters, the costs of which may either be charged directly to such households or be spread over all electricity consumers in that region, through networks passing these costs onto retailers.

Choice of electricity tariff

Retailers continue to explore types of electricity tariffs that will give them a competitive edge while not affecting revenue quality with two or three part tariffs often providing an optimal outcome (Burtt, 1998). The ongoing introduction of TOU meters in Australian states provides a wider range of options, particularly in enabling households to have access to pricing that reflects electricity costs in the wholesale market. To this extent households can then react to the same high prices retailers experience enabling retailers to pass on the costs savings, being a cost pass-through. Prices on a half-hour basis do not provide retailers with a convenient means to include a profit margin (for risk) resulting in either two or three part tariffs becoming more common. The market benefits of providing consumers with access to forecast day ahead prices was evaluated by Valenzueal (2012) noting the value of load shifting on the market’s peak energy needs. Retailers having flat tariffs, thereby not providing useful price signals, are described by Oliva and MacGill (2012), as providing a “schedule of fees intended more for cost recovery than efficient resource allocation” (Oliva and MacGill, 2012, p 7).

Somewhat ironically the reactions already by households to conserve electricity, including purchasing PV, has reduced the peakiness of wholesale electricity prices thereby reducing the effectiveness and need for two or three part pricing.

Wholesale market changes designed to encourage demand-side management

The reactions of households in reducing electricity demand provides both a short and long-term benefit to households and a long-term benefit to the market through reducing the need for additional network investment to accommodate peak demand and through reducing the need for expensive peaking generation. Market rules allow large users, such as smelters, to bid in demand reduction capacities. In late 2014 a demand side rule change was proposed to allow demand aggregators to bid in capacity, opening the door for households to become participants in the wholesale market, an important household conservation development.

For the reasons mentioned above it could be expected that electricity demand is more sensitive to price increases than may have been the case five to ten years ago, and is likely to be the case into the future.

4.4.2 Household electricity consumption behaviour

The potential of household demand-side management (DSM) was quantified by Saddler (2007) who examined the potential in 2007, noting that residential electricity demand was 62,000 GWh in FY 2005, being approximately 25% of national electricity demand. By focussing on water heating, being smaller and with 5-star rating, lagging of water pipes, installing ceiling installation in all houses, improved lighting efficiency and a range of other measures Saddler concluded that demand-side actions could reduce national system demand by 145,000 GWh by 2050. BREE (2015) forecasts total electricity generation to be 332,000 GWh pa by FY 2050 indicating that there is DSM potential to reduce demand by 44% by 2050. What is not known is the extent which such DSM assumptions are already included in these forecasts. If they were fully included then total electricity demand would otherwise have been 477,000 GWh, with the DSM impact then being a 30 percent reduction. Either way these figures highlight the enormous potential for DSM to reduce electricity demand. This is not a key focus of this paper but should be included in any full-scale analysis of how GHG emissions can most cost effectively be reduced in future.

The increasing level of interest shown by in households in seeking to be involved in activities to reduce GHG emissions has increased in pace. Sadler (2014) noted that the reduction in NEM demand in FY 2013, by 8 terawatt hours (TWh), was a result of a mixture of factors including industry restructure, including the partial or complete close down of the Port Kembla steelworks, the Kurri Kurri aluminium smelter and the Clyde oil refinery (contributing 3.6 TWh) and photovoltaics (2.7 TWh). Sadler added:

> Research we have recently completed concludes that the three largest factors contributing to the recent dramatic changes in demand for electricity are:
>
> - the impact of (mainly regulatory) energy efficiency programs
> - structure change in the economy away from electricity intensive industries

- since 2010, the response of electricity consumers, especially residential consumers, to higher electricity prices. (Saddler, 2014, p 3)

Similar comments were made by AEMO (2016) that:

> Residential consumption represents about 30% of total annual consumption in each region. It has been declining in recent years, due to:
>
> - Increased penetration of rooftop PV panels.
> - Appliance and building energy efficiency savings attributed to Federal and State energy efficiency programs.
> - Increased residential process (energy bill stress) also put downward pressure on household electricity consumption. (AEMO, 2016, p 21)

These measures represent the most cost effective means of reducing GHG emissions but are most likely to initially require households to pay higher costs as noted by Orszag (2008) who commented:

> … price increases would be essential to the success of a cap-and-trade program because they would be the most important mechanism through which businesses and households would be encouraged to make investments and behavioural changes that reduced CO_2 emissions (Orszag, 2008, p 5)

The potential for demand-side management is also emphasised in Burtt (2009) and Wagner, Froome and Foster (2010). Both stress the need for time of use meters. Part of the challenge will be to ensure energy efficiency achievements are measured and integrated into whatever carbon reduction schemes are in place, a point made by Bertoldi et al (2005) who also discussed how green certificates, for renewable energy, white certificates, for energy efficiency, and brown certificates, from cap-and-trade schemes, could be integrated, a point also discussed by Meran and Wittman (2012). Oikonomou et al (2012), noted that energy efficiency was the cheapest form of GHG emission reduction. This potential is also recognised by IEA (2014) who commented "Energy efficiency has been referred to as the 'hidden fuel', one that extends energy supplies, increases energy security, lowers carbon emissions and generally supports sustainable economic growth. Yet it is hiding in plain sight: the global energy efficiency market is worth at least US$310 billion a year and growing" (IEA, 2014b, p 2).

Chapter 5 Methodology

Summary

Chapter 5 discusses the approach taken to the build-up of the model, commencing with examining financial flows in the Australian electricity sector and then relating these financial flows to the different types of subsidies and electricity sector activities that give rise to GHG emissions. The outcome was a four part modelling approach covering household PV, large-scale renewable energy, the changing mix of renewable and non-renewable energy and demand-side management.

The household PV model incorporates the various financial factors that households consider when deciding to install PV, being the PV cost and the benefits that arise, from PV output reducing electricity imports and receiving credits from output exported to the grid. These financial factors are converted into payback periods, and compared with the actual uptake of PV and levels of reduced emissions. The analysis is over the period FY 2008 to FY 2014.

The large-scale renewable energy model is similar to the household PV model in determining payback periods but the analysis is over a longer FY 2000 to FY2020 period. Levels of emission reductions are determined in a similar way by noting the higher emission type generation the renewable energy replaces.. Both models are used for sensitivity purpose to assess likely outcomes if any of the input variables are changed. The period FY 2000 to FY 2020 encompasses the period the Australia Commonwealth Government has committed to reducing GHG emissions by 5% as well as capturing the year 2020 when Australia is seeking to have at least 20% of electricity generation from renewable energy sources (Clean Energy Regulator, 2012a).

The changing mix of generation types is viewed to determine the extent to which emissions are reduced when moving from brown coal to black coal to gas to renewable energy.

Demand-side management covers the types of actions households undertake to conserve energy with a model established to measure the extent to which households have, since 2010, reduced electricity consumption in response to higher retail electricity prices.

5.1 Electricity sector financial flows

A wide range of electricity sector financial flows was first examined (Figure 5.1).

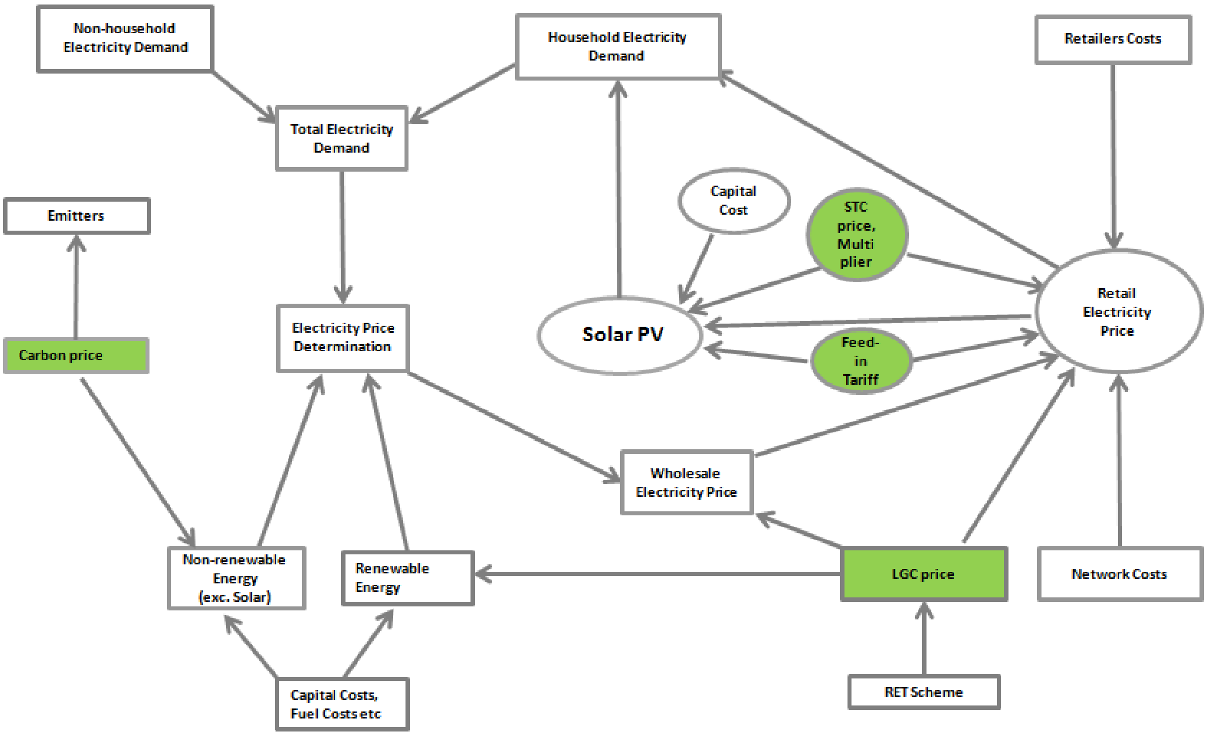

Figure 5-1 Financial flows affecting the electricity sector

The purpose of Figure 5.1, reflecting the situation in Australia in early 2012, is to show that electricity prices are determined through generation, from non-renewable and renewable sources, being dispatched to meet total electricity demand, from household and non-household sources. This process is the responsibility of the Australian Electricity Market Operator (AEMO) who dispatches least cost generator bids (price and quantity) first, which may differ from their actual operating costs, followed by increasingly expensive generator bids up to the level of the cheapest generation that ensures supply matches demand, being the marginal generator. In so doing AEMO uses the marginal generator's bid price to determine the wholesale market price, initially on a five minute basis, which is then averaged to produce half-hourly "spot" prices.

Figure 5.1 also serves the purpose of highlighting, in green, the four non-market inputs which have the effect of lowering GHG emissions. These cover carbon pricing (supporting renewable over non-renewable generation and gas-fired over coal-fired generation), STC prices and feed-in tariffs designed to encourage household PV, and LGCs designed to encourage large-scale renewable energy. The non-market inputs show the cost of subsidies to electricity consumers. Carbon pricing increases wholesale electricity prices, being a cost component to electricity retailers who are also required to make STC, LGC, and FIT payments, the latter passed on by network companies, all of which are contained in consumer electricity prices.

5.2 Linkages of subsidies with electricity sector GHG emissions

The focus of this thesis is on the costs of GHG emission reductions. Hence it is necessary to relate the electricity-related financial links in Figure 5.1 to activities associated with GHG emission reductions (Figure 5.2).

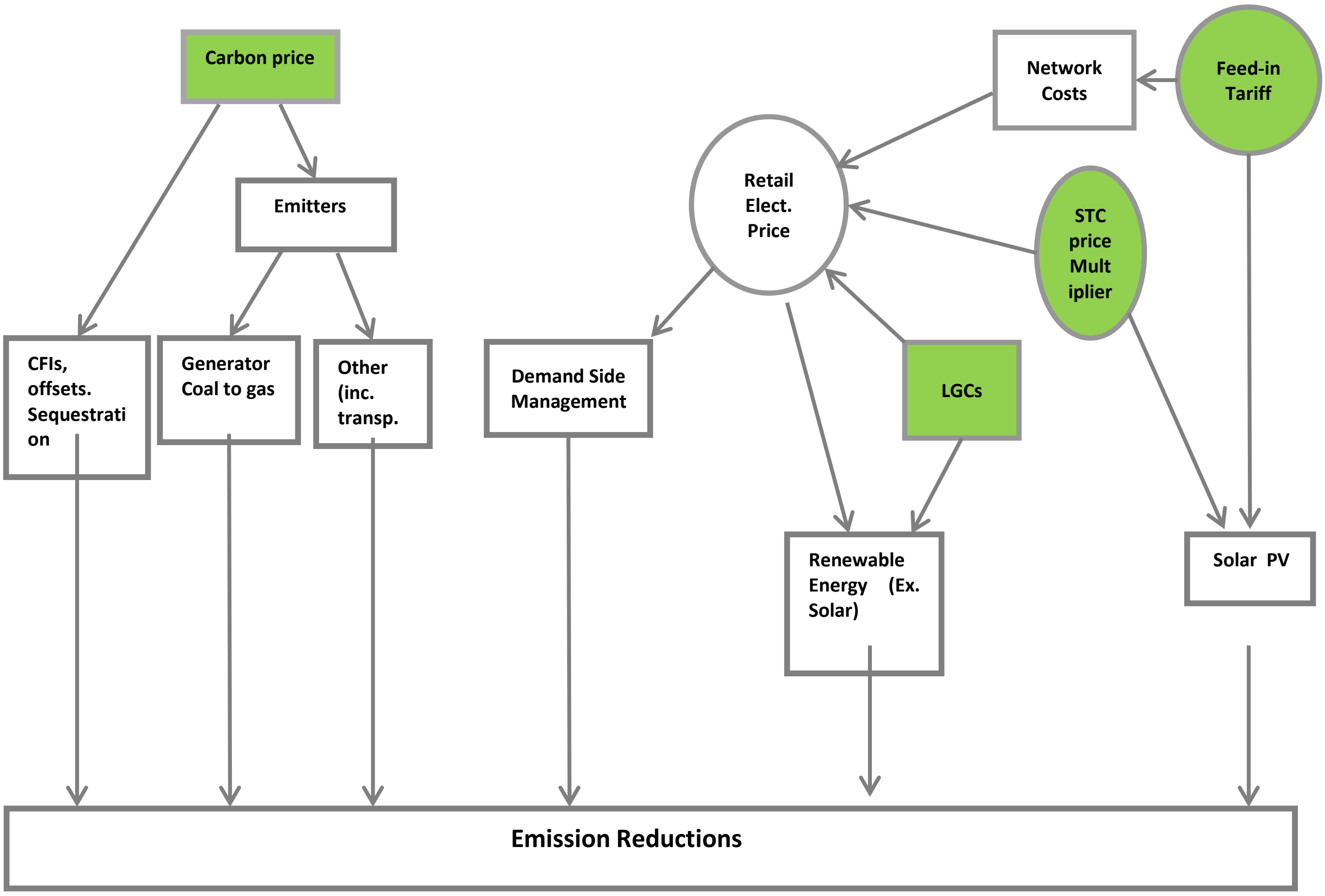

Figure 5-2 Sources of electricity sector emission reduction

Each of the four non-market inputs can be seen to link to GHG emission reduction activities. The six links to GHG emission reductions shown are: firstly demand-side management whereby consumers, in response to increasingly higher electricity prices, reduce electricity consumption either through conservation, possibly by using more efficient electrical appliances, or using PV to displace their need for electricity imported from the grid; secondly increased uptake of PV displacing other more GHG emission intensive generation; thirdly other (large) renewable energy generation displacing more emission intensive generation; fourthly less emission intensive generation, such as increased gas-fired generation and replacing brown with black coal-fired generation, driven by carbon pricing; fifthly other large emitters, such as transport and coal mining companies, becoming more GHG emission efficient in their business activities, and lastly a range of activities that provide GHG reduction benefits arising from a price being placed on carbon. These include Carbon Farming Initiatives (CFIs) created in the agriculture sector, for example through tree planting, carbon offsets created by reducing GHG emissions such as utilising land-fill emissions for electricity creation or flaring and sequestration, whereby carbon dioxide emissions from coal-fired generation are stored underground, also known as carbon capture and storage (CCS).

Of these six GHG emission reduction processes, this thesis addresses the first four although there is the prospect that households could be involved in carbon offsets in future and hence this could be included as part of demand-side management. In effect the modelling relates to electricity sector activities affected by non-market inputs giving rise to GHG emissions. The purpose of the modelling is to allow changes in a non-market variable, as shown in green in Figure 5.2, to flow through to changes in other variables and ultimately to changes in GHG emissions.

There are some electricity-related activities that could be included but instead have been omitted as the beneficial emissions impact arises not through a process that directly reduces GHG emissions but instead through compensating activities. For example CFIs assist in absorbing GHG emissions but only after GHG emissions have been created. In addition CCS is a process designed to ensure GHG emissions are not released into the atmosphere. This is an attempt to address a problem after it has occurred, and in any event is still to be proven to be economic on a large-scale. Wagner and Foster (2011) noted that in Australia a substantially higher carbon price was needed before CCS was viable. Spath (2004) noted that CCS costs could easily be under stated and that a total life cycle approach was needed to reflect the fact that additional energy was needed to compress and transport the gas to underground deposit areas.

5.3 Carbon pricing, emission trading schemes and direct action plan

Carbon pricing, which directly targets carbon emissions, also had a material impact in the electricity sector, when in FY 2013 and FY 2014, through the resultant increase in retail electricity prices, the economics of household PV improved and energy conservation became more apparent. These effects have been modelled. Carbon pricing also resulted in a marked movement from coal-fired generation to gas-fired generation and to renewable energy, with associated emission reductions. Although not modelled the effect has been noted in the model results on an annual basis. This issue is comprehensively analysed in studies by AEMO (2012) and ROAM Consulting (2014). An ETS was proposed but not enacted by the Labor Party by the time it went out of office in 2013. The Coalition’s Direct Action Plan took effect in early 2015, having provision to allow aggregation of small-scale demand reductions which, if coupled with price transparency, could be a valuable market contribution in allowing households to become more active DSM participants and in providing important market price signals.

The various features previously referred to suggested the need for a four part modelling exercise, covering: household PV; large-scale renewable energy; non-renewable energy switching from coal-fired to gas-fired and to renewable energy; and demand-side management by households, relating to energy conservation, PV displacing electricity imported from the grid and, although not modelled, the potential for involvement in demand-side aggregation or carbon offset creation

5.4 Non-modelled aspects of renewable energy

There are various indirect costs and benefits associated with renewable energy projects, which are difficult to quantify and have not been modelled. These externalities reflect real costs (and some benefits) that projects do not experience; instead electricity users, rate payers or tax payers either make payments or benefit. These externalities are not currently experienced by project developers and therefore do not influence their decision-making (in entering into renewable energy projects) but this may not be the case in future, with a greater emphasis expected to be on projects incurring their full costs.

There are also cases where the parties experiencing extra project-related costs do have some ability to reduce these costs, rather than attempt simply to pass them on. Possibly the best example, in the case of PV, is where network companies may have to undertake network upgrades to accommodate electricity being feed back into the grid. Network companies are considering addressing this issue by installing battery storage at network substations to allow electricity to be stored and re-injected into the network when the problem has dissipated (AEMC, 2015). This is a larger-scale approach to similar action households with PV could take when attractive FITs terminate. Households will be driven by maximising the revenue potential of PV whereas networks are driven by reducing costs; different drivers but achieving same peak load reduction on the network. These issues were noted in a UK context by Balcombe et al (2015) who sampled 30 households noting that inclusion of battery storage “Improves the grid demand profile by 28% in terms of grid demand ramp-up requirement and 40% for ramp-downs” (Balcombe et al, 2015, p 393). Although not part of the 20 year model developed, the economics of battery storage as a supplement to household PV has however been examined later in this thesis.

The overall economics of large-scale electricity (battery) storage, although not modelled, is likely to become more prominent in future. As mentioned in Section 2.3 the key areas are molten salt storage associated with large-scale solar energy viability and pumped storage for both hydro and wind generation (PIN, 2013).

Often overlooked are the externalities associated with wind generation, which is forecast to provide the largest share of renewable energy generation to ensure the LRET target is met. ARENA (2013) commented that wind provided 1.5% of Australia's energy in FY 2008 and is forecast to provide 12.1% in FY 2030. The intermittent nature of wind generation means that back up generation, particularly fast start generation such as gas or hydro, is required, being an added expense. In addition networks must be capable of meeting both extremes of wind generation at maximum output and at no output, when back up electricity generation will be necessary which is likely to be "carried" along a different part of the network. In effect double the level of network capacity could be required to ensure supply reliability. Simshauser (2011) concluded that the extra network costs associated with wind generation would be "trivial". Schleicher-Tappeser (2012) noted, in a German context, that because PV is almost viable without subsidies, an aspect also noted by McKinsey (2012), that issues relating to networks and peaking will come more into focus, being the likely future situation in Australia. There are also often unnoticed favourable renewable energy outcomes, such as PV increasing property values (Ma, 2015) and in the case of wind power, farmers receiving extra income for their land being used for generation purposes (Sutherland and Holstead, 2013).

Cross subsidies are coming more into focus with the growth in PV. Nelson et al (2011) concluded that FITs result in low income households subsidise wealthier households by a factor of 3. These examples highlight the fact that subsidies supporting renewable energy are likely to be associated with additional costs. These additional costs will in most cases be paid for by electricity consumers so that as well as the more obvious direct subsidies there are additional non-quantified subsidies paid for by electricity consumers. These have not been modelled but need to be recognised as they are likely to be more substantial over time and could eventually become additional costs experienced by project developers effectively lowering the viability of some renewable energy projects.

5.5 Model concept adopted

The focus of this thesis is on modelling of the relationship between renewable energy subsidies and GHG emission reductions in Australia, of which there is little published research either in Australia or overseas. There are however papers on abatement costs of different types of electricity generation, with the works of McKinsey & Company being prominent. There is some research on a piecemeal basis in Australia, such as Treasury's modelling of carbon and GHG emissions (Treasury, 2011a; Treasury, 2011b), and publications by consulting companies on how carbon pricing has impacted wholesale electricity prices (SKMMMA, 2011) which included a cost benefit analysis of the impact of a national carbon pricing mechanism on the electricity market.

The model developed is a simple year by year capture of the electricity output of renewable energy types, the associated GHG emissions and, where available, input costs. The availability of input data is the key determinant of the detail in which each of the renewable energy types is examined, which is now discussed in descending order of level of detail. Household PV has detailed input costs and revenues data available enabling payback periods and GHG emission reductions to be built up on an individual household basis and factored up to national figures, using numbers of installations and their capacities. Regression analysis of payback periods against levels of new household PV was then used.

The second most detailed analysis was of large-scale renewable energy projects, where input costs and revenues were built up on a project-by-project basis to create payback periods and then factored up to produce national figures. Different subsidies were involved compared with household PV, including grants for specific projects.

The third most detailed level of analysis was on demand-side management, where the focus was on electricity conservation by households in response to the movement in real electricity prices, using regression analysis to produce price elasticities of demand.

The least level of detail has been on non-renewable energy, not being a prime focus of this thesis. Nevertheless there is relevance for example in the impact of carbon pricing on electricity prices, in turn affecting the economics of renewable energy projects, and household energy conservation. There is also the impact of carbon pricing on changing the relative economics of generators output thereby reducing GHG emissions. Each of these is quantitatively examined.

The non-renewable energy analysis modelling does not extend to a level of detail as in the household PV analysis. To do this would have required a sophisticated half-hourly generation (merit order dispatch model, not considered necessary for the purposes of this thesis. Parties such as ROAM Consulting and SKMMMA (now Hatch) have such models that could have been accessed had this been necessary.

A broad measure of the economics of renewable energy projects has been assessed by developing payback periods for new renewable energy projects. It is assumed project developers, rather than financiers, are decision-makers and that all projects are equity funded. Payback periods for each year are compared with levels of new installed capacity. This is used in most detail in the case of household PV where regression analysis concluded that, in broad terms, the shorter the payback period the greater the aggregate capacity of newly installed PV. There are some data-related limitations such as FITs changing mid-year, the lagging between financial incentives and actual installation, and a higher uptake occurring when it was announced that an attractive FIT was about to end but close comparisons between model-determined FIT payments and published data meant they were not a major concern. The payback to new installations relationship was used to estimate the likely uptake of PV in the future based on forecast changes in input variables such as capital costs, STC multipliers and FITs. Unlike larger scale renewable energy projects, where the price of the environmental credit (LGC) is based on supply and demand, the PV solar credit (STC) is capped at AU$40/STC thereby simplifying this part of the analysis. A similar payback concept was applied to larger renewable energy projects but the outcome, that is the relationship of the payback period to newly installed capacity, is of value but more approximate because such projects have longer lead times, and are impacted by other factors such as environmental approvals, network or transmission agreements and possible one-off grants.

These aspects give rise to a difference in the modelling approach between household PV uptake, which is built up from the attitudes of households as a whole, and larger renewable energy projects that include analysis of some much larger projects on a one-off basis, using various sources of information. New wind farms and solar farms are generally noted in the media with useful comments also provided by grant providers. Bagasse (from new sugar processing plants) and new hydro projects occur less frequently and would, in the few cases of them possibly being viable, have materially longer lead times.

Accessing needed data, particularly back to FY 2000 has been a challenge in some areas. Information such as wholesale electricity prices is readily available (from the Australian Electricity Market Operator). In addition generation data in terms of annual output by generation type is readily available (from Bureau of Resources and Energy Economics) but not the marginal generator setting the wholesale electricity price. Knowing the marginal generator is important because if electricity consumption reduces (or increases) it is important to know the type of generation that is affected to know how the level of GHG emissions are affected. Another data issue relates to retail electricity prices because as states deregulate, retailers franchise tariffs are no longer applicable. Instead there are various prices offered to the market from competing retailers. Victoria was the state to first deregulate making this the state which has the least accurate information on household electricity prices.

The model has been developed so that a wide range of input variables can be altered affecting outcomes such as generation output, emission reductions and the likelihood Australia's emission targets will be met. The build-up of retail electricity price components in the model is discussed in Appendix A.

5.6 Household PV model approach

The main focus of the 20 year model is on household PV in Australia. The model adopted takes the PV related parts of the flows shown in Figure 5.2 and then views the financial relationship between these variables that either directly or indirectly impact on household PV, thereby producing the flows shown in Figure 5.3.

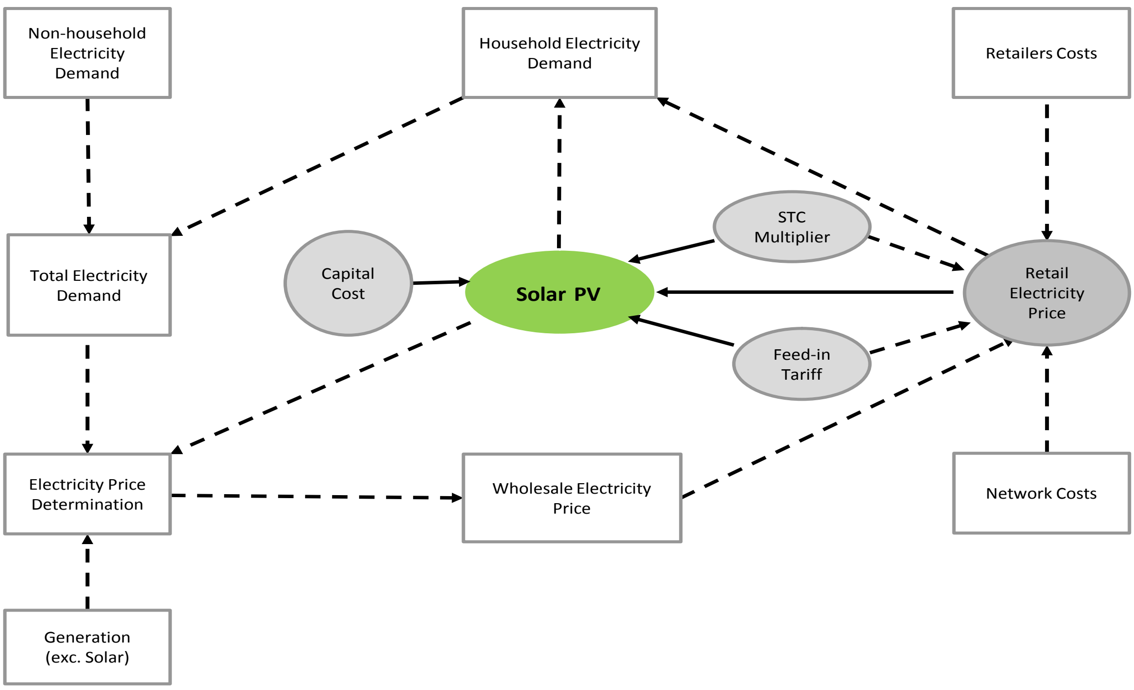

Figure 5-3 Financial flows affecting household PV decision-making

In broad terms, PV households make purchasing decisions based on household PV installation cost ("Capital Cost"), being the installed PV cost discounted by the value of STCs ("STC" and "multiplier") provided by installers, and expectations of revenue from FITs and savings from reduced imported electricity costs. Households typically assign STCs to installers who discount PV installation prices by the market value of the STCs, less installers' margin of 20% (Martin and Rice, 2013).

PV also has some less obvious positive and negative impacts on the wholesale energy market. Households, in utilising solar electricity for a portion of their electricity needs, reduce national electricity market (NEM) demand from the grid. This has implications generally of a favourable nature to consumers, through depressing wholesale electricity prices. In the short-term the reduction arises from increased competition between generators to meet lower demand, as has been occurring in Australia to the concern of generators (Simshauser, 2014). There is also a substitution impact arising from PV exports replacing more expensive generation. Wurzburg et al (2013) examined the renewable energy impact on wholesale electricity prices in European countries, particularly Germany and Spain, concluding, in line with results of 19 other papers they viewed, that renewable energy reduced wholesale electricity prices by between 4 and 12 percent, with wind having the greatest impact.

Ciarreta et al (2014) also noted this market price impact concluding that, in Spain over the period 2008 to 2012, green energy paid for itself in the early years but in later years, following strong growth, the impact became a net cost. Although several authors observed the beneficial lower wholesale price impact Milstein and Tishler (2011) also noted the increases in price volatility, and hence increased risk. Similar conclusions were reached in Australia by Australian Government Climate Change Authority (2012) and ROAM (2012).

Distribution companies need to make modifications to accommodate backflows of electricity when electricity is exported to the grid (Australian Government Climate Change Authority, 2012, p 43). The impacts on distribution companies are difficult to quantify, but on balance they are more likely to be unfavourable than favourable. This is supported by various reports viewed by Syed (2012).

On overcast days non-solar generation ("back up generation") will be required which, by definition will be poorly utilised. This presents a real market challenge because of the expected growth in intermittent renewable energy (Spiecker and Weber, 2014; Molyneaux et al, 2013), discussed later in this thesis in viewing electricity storage options. Wurzburg et al (2013, p 160) commented "A more intensive use of renewables may require an increase of conventional back-up capacity to cope with the volatility of renewable generation" adding that "These elements may, in turn, affect long-run electricity prices in the opposite direction". A more extreme comment was made by Feuerriegel and Neumann (2014) who suggested that electricity retailers can partially meet the back-up generation problem through demand response. They modelled this suggestion concluding that in doing this, retailers costs could be reduced by 3.52%.

There is an administration “Cost to manage” arising from large numbers of households, rather than a small number of large-scale generators, having to make investment decisions, go through the process of installation, have retailers modify invoices and gather extra meter data, as well as the AEMO having to accommodate a less certain form of generation into its dispatch process. These extra activities (involving a large number of parties) could be seen as negative but because households have decision control, rather than large businesses, this is considered a broadly neutral outcome.

An “Efficiency of decision making” benefit arises from solar output automatically occurring, that is without human involvement, in contrast with non-renewable market generators bidding their output into the wholesale market on a five minute basis.

These non-quantifiable costs and benefits, from a consumer viewpoint, are summarised in Table 5.1, where H is high market impact, M is medium market impact and L is low market impact.

Table 5-1 Indirect market consequences of PV

Market Feature and Market Impact	Positive	Neutral	Negative
NEM demand reduction	H		
Displacement of higher cost generation	H		
Distribution upgrades			M
Backup generation required			H
Cost to manage		L	
Efficiency of decision making	M		

Note that these impacts are from the perspective of consumers. They are, on balance, favourable in the short-term but less likely to be in the long-term when some of these unfavourable cost externalities could be passed back to all consumers. Non-renewable energy generators who have made investment decisions based on demand growth forecasts which have not transpired, are likely to be negatively impacted in the short-term (Simshauser, 2014).

5.6.1 *Choices of project viability*

Research into the viability of household PV has tended to focus mostly on how changes in cost and revenue components affect viability (Talavera et al, 2010; Orioli and Gangi, 2014). Talavera et al (2010) noted the three standard forms of financial evaluation being net present value (NPV), internal rate of return (IRR) and payback period, commenting that the payback method ignores cash flows beyond the payback period but is the easiest to understand. The IRR method requires the life of the system to be included in the calculations which is an uncertain variable in the early stages of the life of PV systems.Orioli and Gangi (2014) adopted the NPV approach using the lifespan as the 20 year period of subsidies applying in Italy. Of particular relevance in the work of

Orioli and Gangi (2014) is the sensitivity analysis undertaken of the impact of changes in input costs on NPV, the closest approach that any articles show to the sensitivity analyses undertaken in this thesis.

No research articles could be found linking costs and levels of subsidies firstly to payback periods and then to the uptake of household PV, possibly because time series are either too short (given household PV developments are comparatively recent) or because by using say weekly rather than annual data, the uptake is unlikely to show meaningful trends. Grau (2014) examined, on a weekly basis, the relationship, in Germany, between net benefits (present value of FITs less PV costs) and PV installations over the period 2009 to 2011. Grau (2014) noted that FIT levels had been declining at a similar rate to the decline in PV costs so net benefits did not show large variations over time. Complicating the analysis, as mentioned above, is the fact that in reality there would be many weeks before improved viability was reflected in increased PV uptake.

The approach taken in this thesis is to use the payback method of assessing viability rather than IRR or cash flow methods. As discussed in Fais et al (2014) the payback method is less complex than the IRR method, and hence easier for households to understand, but omits future benefits after the end of the payback period. Omitting future benefits beyond the payback period has some practical relevance because they ignore the possibility that inverters do not last beyond the payback period and that FITs might be changed, both being unlikely but nevertheless possible outcomes. Perez et al (2004) compared the payback method with ongoing cash flows concluding that simple payback methods may not produce results as attractive as using annual cash flows. Hence use of the payback method in this thesis could be considered a conservative approach to viability.

5.6.2 *Financial components*

The model used in this thesis brings together the financial costs and benefits that Australian households experience in deciding whether to install PV and converts them to payback periods, being the number of years required for the benefits to exceed the initial outlay. This is captured in Figure 5.4.

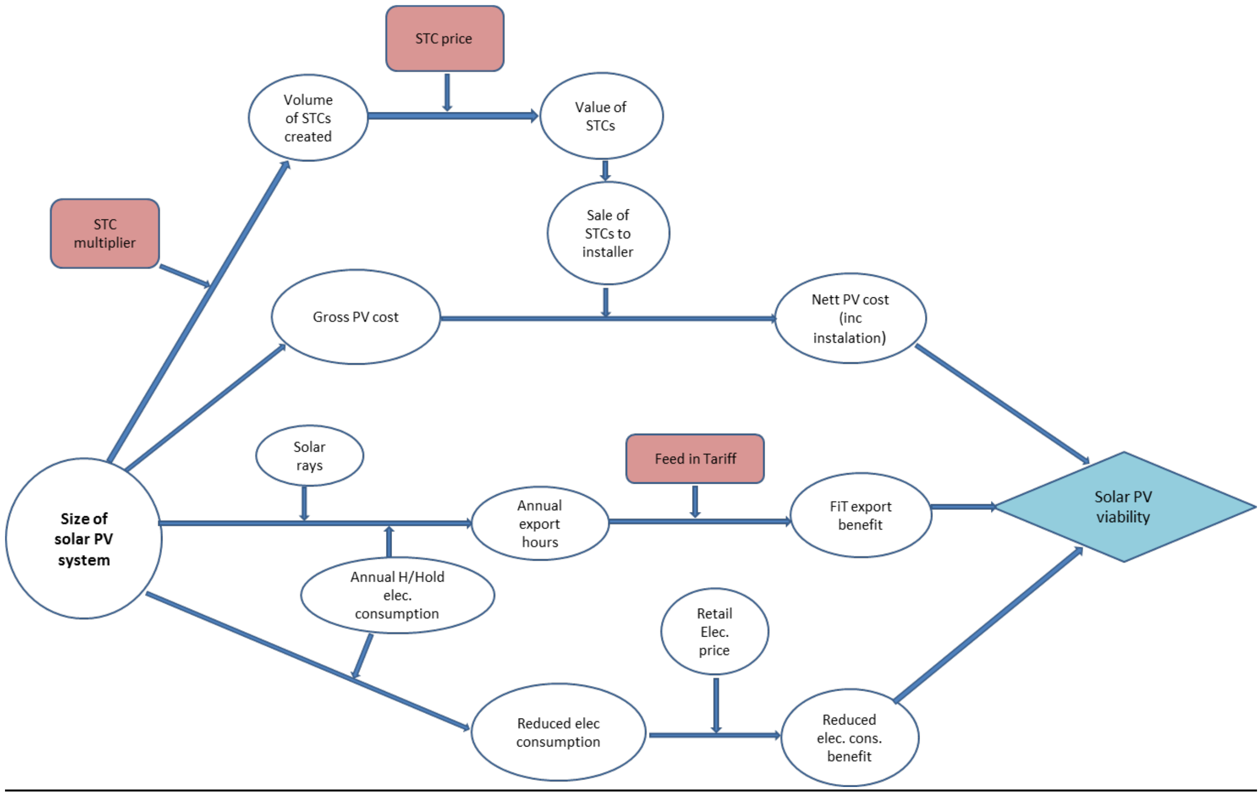

Figure 5-4 Process of determining household PV payback periods

Annual payback periods are regressed against actual annual capacities of new household PV installations to obtain the “best fit”. The output of household PV is used to assess the associated reduction in GHG emissions, as a result of less coal-fired and gas-fired generation being required. Sensitivity analyses are then undertaken to show the relative importance of input assumptions, being either of a market or political nature, in determining levels of household PV.

The analysis has limitations in that the regression analysis is over a comparatively short nine year time frame and there are some necessary data conversions from calendar to financial years. The analysis is on an Australian-wide basis requiring state-weighting of some data, but where this was considered an over-approximation, such as with state FITs, separate state analyses were undertaken.

Size of PV systems, costs and STC impact

The size of PV systems installed in Australia has been gradually increasing since 2000 from between 1.5 kW and 2.0 kW to an average installed size of over 3.0 kW (SunWiz, 2013), as shown in Figure 5.5.

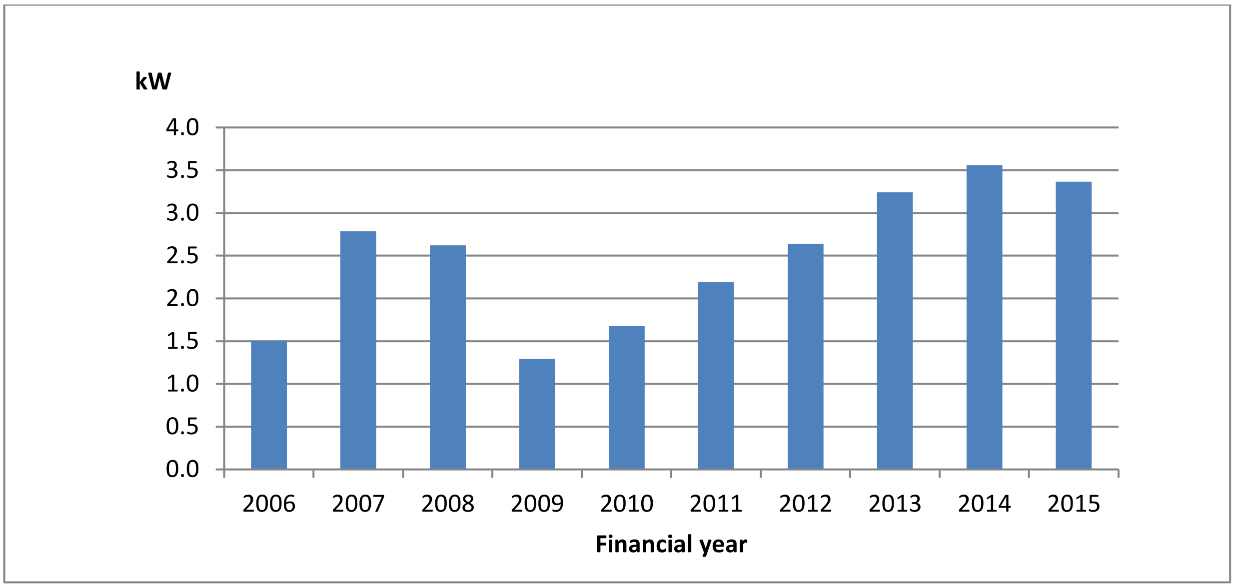

Figure 5-5 Trend in Australian household new PV system sizes

Source: Green Energy Markets (2014a)

System size increase is partly a reflection of declining costs, which began falling in 2008 due to oversupply in China (Yuan et al, 2014), with production costs dropping to a tenth of earlier levels (Honghang et al, 2014b) combined with the strong Australian dollar (Australian PV Association, 2011; Australian PV Association, 2012).These factors, as well as the STC multiplier, combined to provide the most attractive financial conditions for household PV between FY 2011 and FY 2013, as reflected in payback periods of less than four years.

Since 2010 the decline in household PV unit costs appears to have stabilised (Figure 5.6), although de La Tour et al (2013) believe further reductions are possible, and even though FITs are lower than they were five years ago the demand for household PV remains reasonably strong (Clean Energy Council, 2013). Nevertheless at some stage a saturation level will be reached whereby the non-PV household group will take an increasing level of enticement to be attracted to PV. In late 2013 the Australian states of Queensland and South Australia penetration rates had increased to 22% and 25% respectively with a nation-wide average of 14% (Parkinson, 2013).

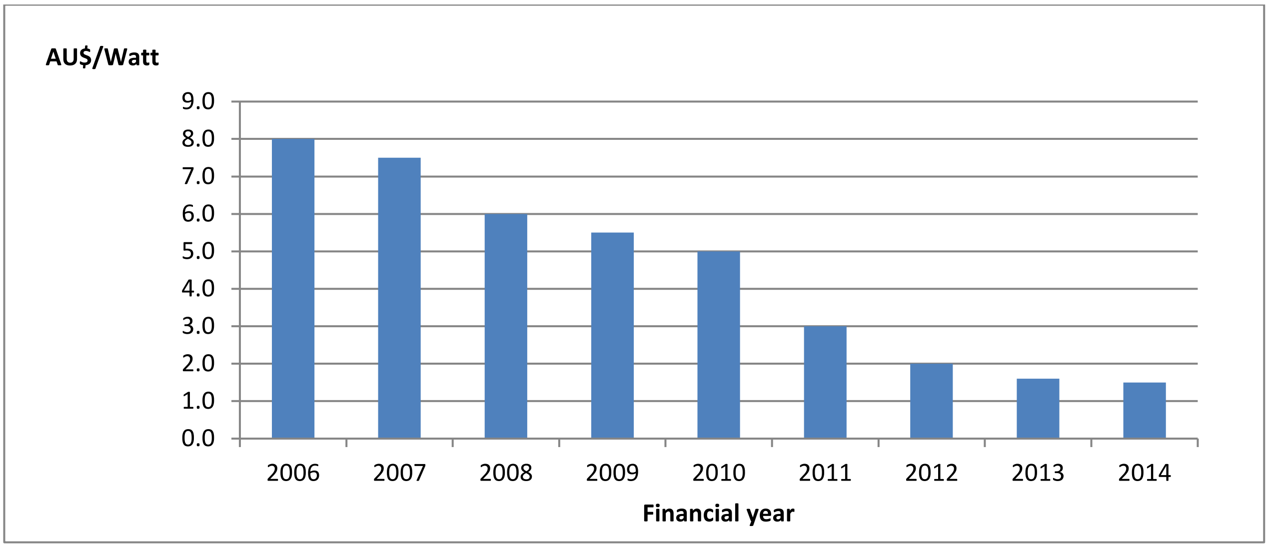

Figure 5-6 Trend in Australian PV unit costs

Source: Australian PVA (2011), Australian PV Institute (2015)

Household PV costs are net of the value of 15 future years of STC benefits which installers seek to be assigned to them from households thereby reducing the PV costs paid by households. STCs generally have a market price range of between AU$35/STC and AU$40/STC (Clean Energy Regulator, 2015) but installers take substantial margins of at least 20% (Martin and Rice, 2013), which unfortunately most households are not aware of. This is recognised in the model.

Between FY 2010 and FY 2013 additional incentives were provided by the Australian government in the form of multiples of STCs that were deemed to be produced up to the first 1.5 kW of capacity. This multiplier increased from a factor of 1 in FY 2009 to 5 in FY 2010. That is for PV systems installed in FY 2010 households could receive 150 deemed STCs per solar from each installation[5]. At an installers price of AU$32/STC this converts to a AU$4,800 benefit. Installation of a 1.7 kW system in FY 2010 cost about AU$8,800 which meant that installers could afford to price 1.7 kW systems at AU$4,000, providing a 5.4 year payback period. Two years later the installed price of systems dropped substantially, from AU$5,000/kW to AU$2,000/kW, more than compensating for the STC multiplier dropping to a factor of 3, resulting in FY 2012 having the lowest payback period of 2.8 years.

STC costs included in household electricity tariffs

In Australia, electricity retailers are required to purchase a percentage of their sales in the form of STCs (and also LGCs) known as the Small-Scale Technology Percentage (STP). The STP is set

[5] The 150 was determined by multiplying 5 (the multiplier) by 15 (the number of years the allocation could be applied to) by 2 (the number of megawatt hours deemed to be produced annually by a 1.5 kW solar installation)
From 1 January 2017 the years of allocation are to be reduced by one for that year and each subsequent year.

at the start of each calendar year with a "true up" at year end year to approximate the supply of STCs that are created from PV installations. In the years of high PV uptake this percentage is much higher than in other years. The trend in the STC purchase proportions (Table 5.2) is a useful guide to the trend in the uptake of household PV and expectations as determined by the Clean Energy Regulator. The lower, more recent, percentages reflect the regulator's expectation of household PV uptake in future.

Table 5-2 Proportion of STCs required to be purchased by electricity retailers

Calendar year	Retailer STC proportion
2008	3.14%
2009	3.65%
2010	19.70%
2011	14.80%
2012	23.95%
2013	19.70%
2014	10.48%
2015	10.10%
2016	10.32%

Source: Clean Energy Regulator

Average daily hours of consumption offset and export

Households financially benefit from PV by reducing imported electricity and by obtaining FIT payments from exported electricity. For modelling purposes it was assumed that on an "average" day electricity consumption is reduced 2.0 hours, and 1.5 hours of electricity is exported to the grid, that is total daily solar output occurs for 3.5 hours each day (AEMO, 2012; NSW Government, 2011; RAA, 2014). Model sensitivities are run on these assumptions. An indication of how household PV affects electricity consumption and exports is shown in Figure 5.7, utilising data contained in Frontier Economics (2012) which is based on 10,000 households in a NSW network area consuming an average 8,000 kWh pa. It is difficult to obtain accurate household consumption data as most Australian households do not have time-of-use (TOU) meters, although this is gradually changing. The figure of 8,000 kWh used by Frontier Economics (2012) does however compare favourably with the nationwide average household electricity consumption figure of 7,100 kWh pa reported by Clean Energy Council (2012).

The household consumption load shape used by Frontier Economics (2012) was compared with AEMO's "net system load profile", that is electricity consumption net of TOU metered consumption in 2013 (AEMO, 2014). The result was very similar with twin peak ratios of 67% for Frontier Economics (2012) and 71% for AEMO (2014) and trough to peak ratios of 44% for

Frontier Economics (2012) and 42% for AEMO (2014). An effective 2.0 kW PV system has been used, being the average PV system size in Australia in 2011 (Green Energy Markets, 2014a).

A similar analysis was undertaken by Ausgrid (2014) who gathered half-hour data from 300 solar customers in their NSW network over the FY 2013 year. Solar system size was slightly smaller (1.7 MW) but gross generation averaged 3.6 hours each day, marginally greater than assumed in this thesis. Peakiness of the load was also greater but this could reflect the sample being solar customers who are m ore likely to benefit from PV compared with non-solar customers.

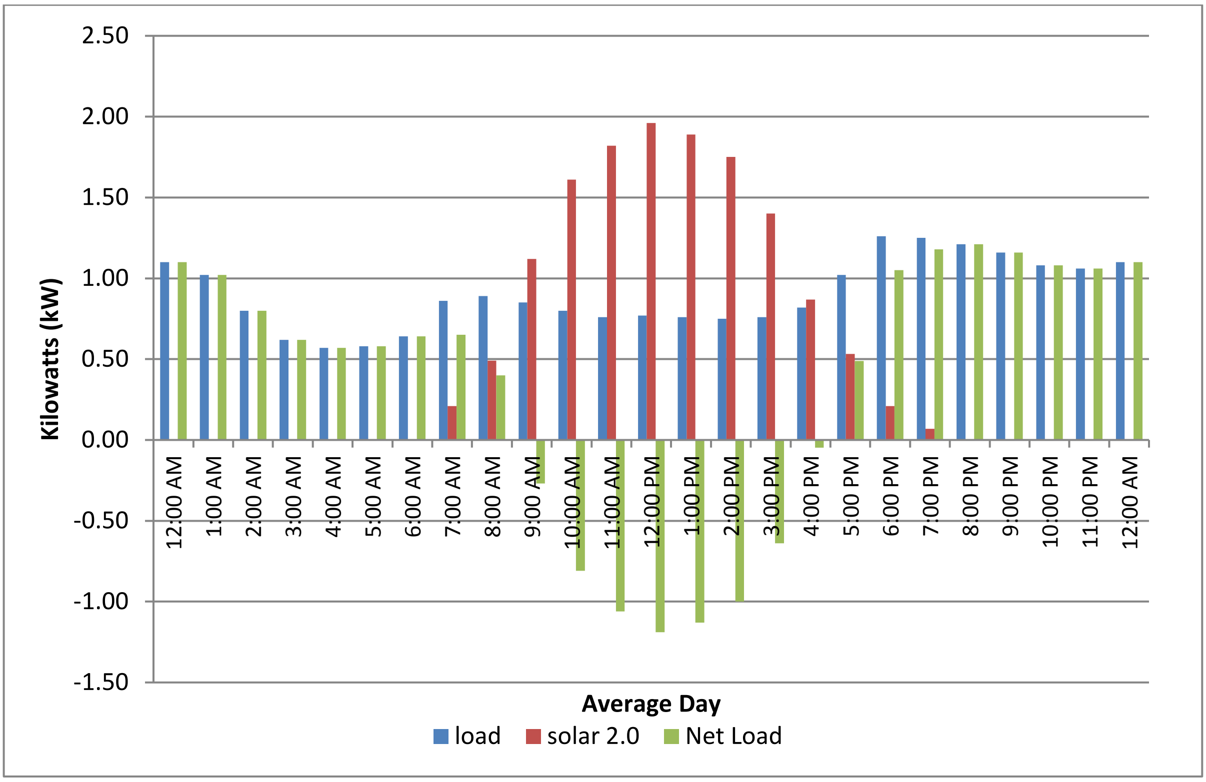

Figure 5-7 PV impact on household electricity consumption in NSW Australia

Source: Frontier Economics (2012)

Annual variation in feed- in tariffs

Commencing in 2008 states and territories gradually introduced FITs. The average FIT increased from being negligible in FY 2008 to AU20c/kWh in FY 2009 to an effective[6] peak of AU58c/kWh in FY 2011, due largely to the NSW gross FIT of AU60c/kWh, and then gradually declined to the current average of AU5c/kWh (Australian PV Association, 2012). An additional AU6 to AU8c/kWh, is commonly added to the FIT, being the value of the exported electricity to

[6] Gross FITs were converted to effective net FITs by also including the difference between the FIT and retail electricity price for consumed electricity in the net FIT.

the retailer involved, but this is not included as part of consumer subsidies. The attractiveness of these early FITs can be seen by comparison with the typical average retail tariff in FY 2013 of AU26c/kWh (AEMC, 2013; Simshauser, 2014).

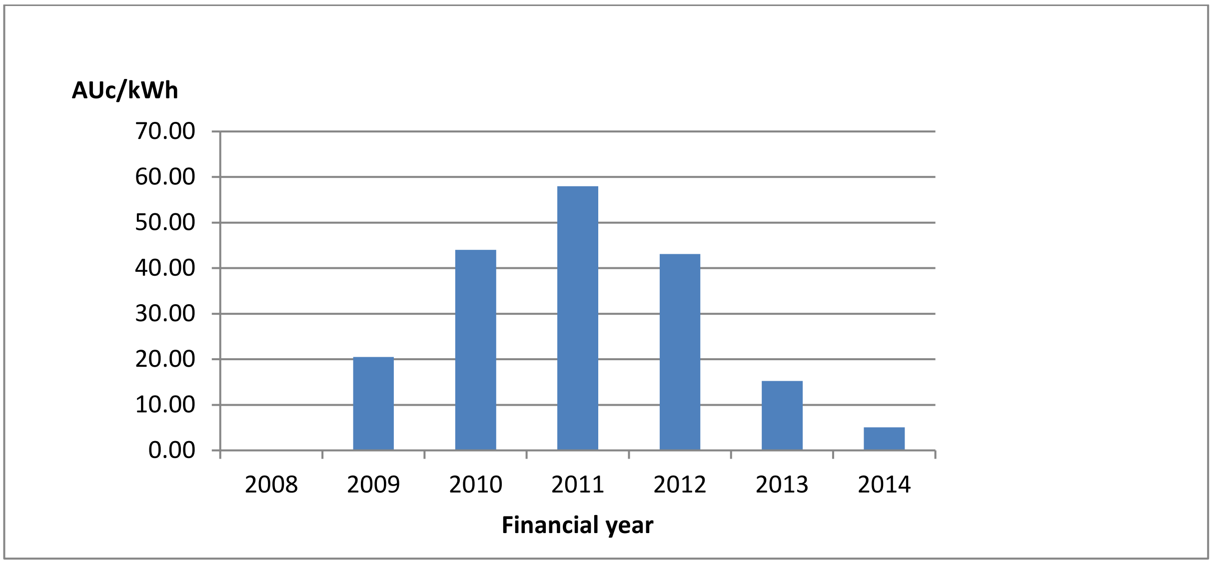

Figure 5-8 Trend in Australian feed-in tariffs

Source: Australian PVA (2011)

The combination of the subsidy components of STCs and FITs is shown in Figure 5.9.

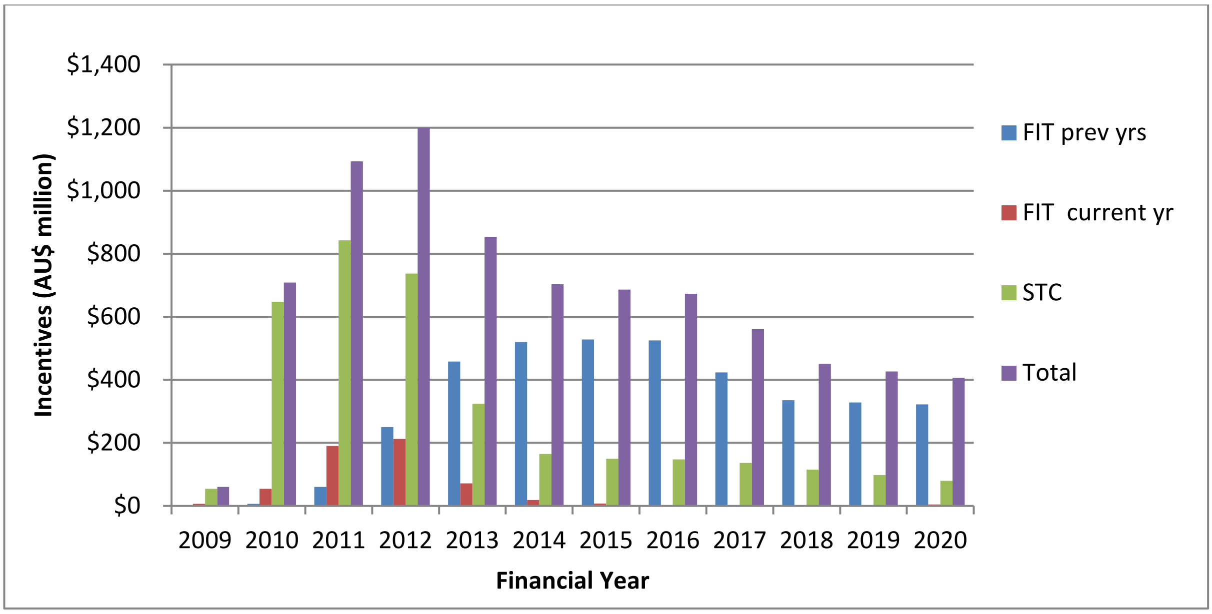

Figure 5-9 PV subsidies by financial year in Australia

Source: See Figure 5.8 and Clean Energy Regulator

Of particular significance is the impact from STCs in FY 2011 and the increasing contribution from FITs; the latter reflecting the fact that although attractive FITs averaged AU58c/kWh in FY

2011 reducing to AU15c/kWh in FY 2013, the historically attractive FY 2011 FITs continue for those households that secured them for five to 20 years, depending on the state involved.

The STC subsidies, reflecting STC prices and STC multipliers, only apply in the year concerned so with the STC multiplier reducing the STC subsidy eventually falls below the FIT subsidy. It is estimated that in FY 2014 of the total subsidy of AU$704 million, AU$520 million or 74% of the subsidy relates to the FIT of previous years. This highlights future policy issues including the fact that, because of historic high FITs, electricity consumers will continue to subsidise PV households at an average AU$500 million pa over the next five years, but dropping to AU$400 million pa post 2020 due to termination of most of the high FITs. (Australian PV Association, 2012). It is the ongoing cost of FITs that makes the scheme cost-inefficient as the payback periods will have been well exceeded much earlier than 2020. This concern has been experienced in many other countries as mentioned in Section 2.1.2.

Determination of household tariffs

In Australia household electricity prices are set either by regulation or through competition between retailers. Retail deregulation has been gradually occurring in each state, beginning in Victoria in 2004. Where deregulation has yet to occur regulatory bodies in each state determine household electricity tariffs through similar component build-up processes with the two largest components being network, including transmission, charges determined by the Australian Energy Regulator, and energy charges comprising a mix of spot prices, electricity derivative prices and long run costs of new generation (Queensland Competition Authority, 2013, p 22). Added to this is a retailer margin, covering overheads, renewable energy and a margin for risk, being in the order of 11% to 15% (Bureau of Resources and Energy Economics, 2013).

Household tariffs have been increasing in real terms over the analysis period, providing an additional incentive to households to install PV. The main reason for the increases has been network companies initially spending to levels that guaranteed security of supply. Network charge increases are expected to be less substantial in future because the Australian Energy Regulator has sought a more prudent expenditure approach, in effect changing from a “n – 1” approach, with considerable redundancy, to a level where at the worst some occasional blackouts could occur (Simshauser, 2014).

5.6.3 *PV impact on GHG emissions*

Household PV impacts on GHG reductions in two ways: generation reduction and generation displacement. Generation reduction occurs through solar being used for domestic electricity consumption (with the excess being exported to the grid). This is part of the reason why Australian electricity demand has been falling in recent years, reducing generation required with a consequent reduction in GHG emissions. The actual reduction reflects the fuel types of generation not now required, being the "marginal" generators. As revealed in Figure 5.7 this occurs, on average between 7.00 am and 6.00 pm, when (in Australia in 2012) 38% of marginal generation was gas-fired (AEMO, 2014). Gas-fired generation emissions in Australia at that time averaged 0.60 t CO2e/MWh, in comparison with coal-fired generation at 1.02 t CO2e/MWh (Australian Government Department of Climate Change and Energy Efficiency, 2012a; Skoufa and Tamaschke, 2011; Energy Supply Association Australia, 2010). Gas and coal-fired generation together produced an overall weighted average of 0.86 t CO2e/MWh. Hence in broad terms in Australia, GHG reductions of 0.86 t CO2e occur for each MWh of reduced electricity consumption. This approach and the results are similar to those in Oliva and MacGill (2011).

The second impact arises from exported PV displacing generation which would otherwise have been required to meet electricity demand. Solar output is generated between 7.00 am and 7.00 pm (Figure 5.7) but because it is first used to satisfy domestic demand the period of exporting is between 10.00 am and 3.00 pm (AEMO, 2012; Burtt, 2009). During these five hours the gas-fired generation proportion was (in Australia in 2012) 17%. Using the same method as for generation reduction produces GHG reductions of 0.93 t CO2e/ MWh. It is these generation reduction and displacement impacts that, together, determine the GHG reduction benefit from PV.

The emission benefits are however marginally less than those determined by this calculation because PV, of itself, involves GHG emissions in the process of solar panel manufacture (Weisser and Strasse, 2007; Fthenakis et al, 2008) the latter making their determination through analysing the lifecycle of a 1.8 kW PV system in either southern Europe or USA. This has been captured in the model by reducing the PV emission benefit by 5%, being at the upper end of the range suggested by Lu et al (2010).

5.7 Large-scale renewable energy model approach

Large-scale renewable energy, being renewable energy other than household PV, has been modelled in less detail than that of household PV and hence does not allow the same form of sensitivity analysis. This reflects the level of available data detail and the different type of decision-making involved in projects of a much larger scale than household PV. Project decisions involve costs, subsidies and revenues peculiar to each project. Rather than uniform state FITs being available, project developers are likely to seek fixed energy and LGC pricing from electricity retailers for their output in the form of power purchase agreements (PPAs), and may also seek financial support on a one-off basis from the state government in the region involved. Nevertheless with the level of aggregated data available it was possible to determine realistic payback periods, in a similar manner to household PV, which was used as part of a broad analysis for each of large-scale solar, wind, biomass and hydro.

The need for large renewable projects to have fixed output pricing is a reflection of the desire to have financial certainty, sought in particular by financiers. The alternative is to go “merchant”, that is to receive pool price revenue (from AEMO, the grid operator). Pool prices are determined on a half-hour basis and can vary between -AU$1,000 and AU$12,500/MWh, creating revenue volatility that project financiers prefer to avoid.

As with household PV, large-scale renewable projects can also access renewable energy credits, being large-scale generation credits (LGCs). Unlike STCs, which have a legislative AU$40/MWh price cap, and a trading price range typically within a price range of AU$2/MWh to AU$4/MWh, LGCs have a much higher cap at AU$92.85/MWh and a much wider trading range, reflecting both political factors and future expectations of large-scale renewable energy projects. Political influences were most noticeable during the period leading up to the revised 33,000 GWh total renewable energy target in late 2104 and early 2015 (Graham et al, 2013). This markedly changed in early 2015 with the market reacting positively to the increased certainty (Figure 5.10).

5.7.1 *Key aspects of model data analysis*

Assumptions used for model build of each large-scale renewable energy type are discussed in detail in Appendix A3. In summary, for each year there are four aspects of model data analysis. The first involved ensuring capacity (in MW) and annual hours of operation produce output that approximates annual output advised by the Bureau of Resources and Energy Economics (BREE), a function now under the control of the Office of the Chief Economist. Levels of (MW) capacity were available from ESAA, EGA (2010) and EGA (2014). This aspect of analysis is important in assessing how Australia has been and will progress towards meeting its target of at least 20% of energy being met by renewable energy in 2020.

The second aspect of model data analysis related to the process by which renewable energy growth is stimulated, being through LGCs (and grants), to help ensure Australia meets the 20% renewable energy target. LGCs are determined from a 1997 output baseline, but used from 2000, for each energy type and reported in the Clean Energy Regulator’s REC Registry making it critical that the model reflects these LGC numbers, This was a time-consuming analysis as the Registry is very detailed and involved the need to obtain explanations from the CER. As an example the model-determined volume of hydro LGCs created was less than that shown in REC Registry, suggesting a lower baseline than that determined by 1997 output levels, as observed by MacGill et al (2006) who commented that some analysts had “identified that baselines for some of Australia’s large-scale hydro generators may have been set below their present long run average system yield” (MacGill et al, 2006, p 16). On contacting the CER I was advised hydro energy baselines change year by year.

The model uses BREE calibrated output figures from which were deducted CER baseline figures to determine LGC figures. These LGC figures plus grants represent large-scale renewable energy subsidies, the focus of this thesis.

The third aspect of model data analysis involved expanding the information contained in first two aspects of data analysis, in effect moving from volume to financial data, to enable payback periods to be determined for each renewable energy type for each year. This was considered necessary to ensure input data, such as the level of renewable energy subsidies, could be reduced to determine the effect on pay back periods and hence the likelihood that renewable energy growth might be reduced, in a similar manner to the approach with household PV. The financial aspects are discussed below.

The fourth aspect of model data analysis related to the reduction in GHG emissions arising from the growth in renewable energy, and hence the contribution made towards Australia meeting its 5 % reduction in GHG emissions. This was a comparatively simple process as the second aspect of model data analysis determined renewable energy growth volume and as was the case with household PV a counter-factual approach was taken to determine the type of generation displaced and hence the level of emission reductions.

5.7.2 *Model Data Input*

Assumptions relating to financial model inputs, output growth and carbon intensity factors are now discussed. Capital costs, developed from a cost per MW basis (CSIRO, 2014; ARENA, 2015), were used to develop the capital costs for each renewable energy type. Revenue was determined from energy pool prices and contract prices plus LGC revenue For LGCs a continuation of the most recent AU$60/MWh price has been used (Figure 5.10), although recent data suggests this could be a conservative assumption (Mercari, 2015). In practice contract LGC prices would be lower than those shown in Figure 5.10 but the recent increases in LGC prices would broadly compensate for this adjustment.

Pool prices used were the same for each renewable energy type except for a sculpting factor used to convert annual average flat pool prices to pool prices specific to each renewable energy type. Sculpting factors were applied as follows: for bagasse output, where production is mostly in summer, a 40% premium was applied reflecting higher summer pool prices compared with the NEM annual average pool price; for solar energy, where output is mostly during times of high demand and high pool prices, a 50 % premium to average pool prices was applied up to FY 2013 then gradually reduced reflecting, in particular, the solar generation impact on the distribution of pool prices; with wind energy having a 10% discount factor reflecting greater uncertainty in wind output. Hydro output is often run-of-river but because there are sometimes opportunities to hold back water to take advantage of higher pool prices a 10% premium to average pool prices was applied. These premia and discount factors were based on market information, AEMO pool price data and research carried out by the author, having PPA pricing responsibilities at Energex and Ergon Energy over the period 1999 to 2012.

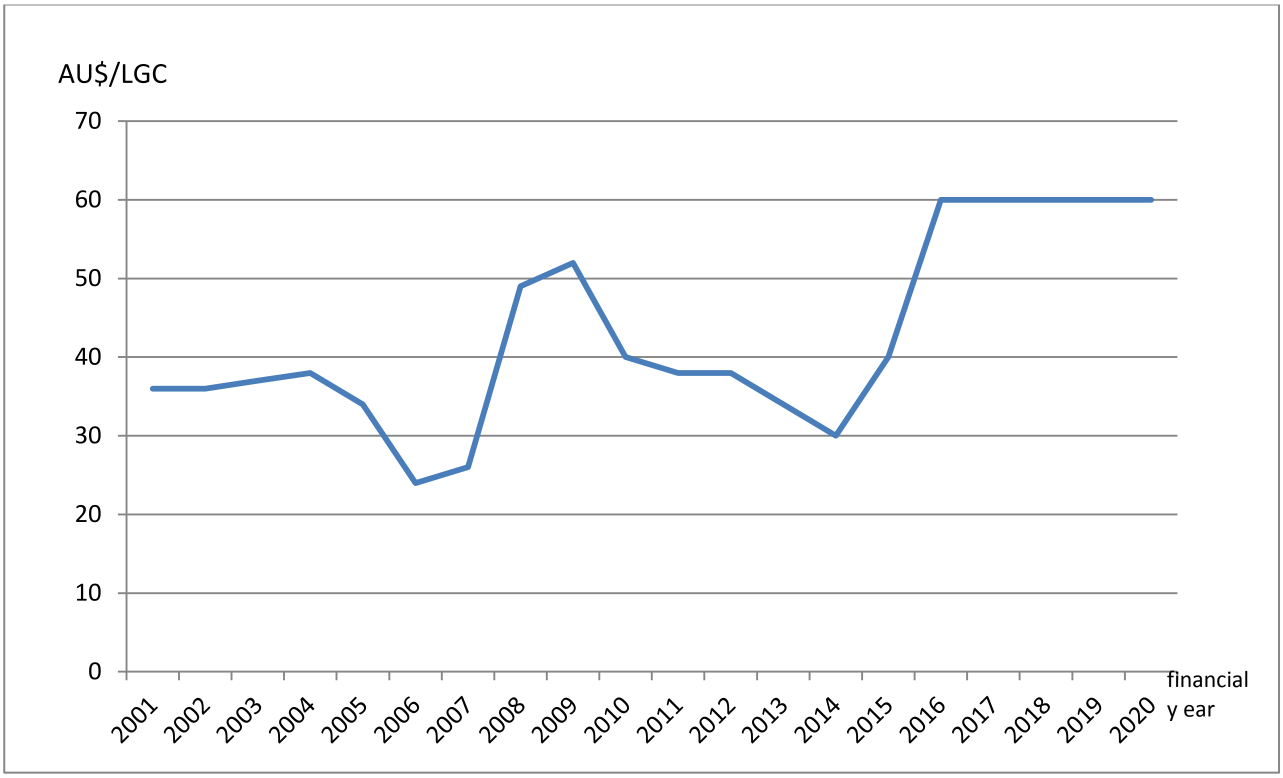

Figure 5-10 Large-scale generation certificate price trend

Source: IES. (2007), Australian Government Climate Change Authority (2012), Green Energy Markets (2014a), Mercari (2015)

Information on revenue from one-off grants, and low cost finance, from Commonwealth and state governments is not always made public. Fortunately the Australian Renewable Energy Agency

(ARENA) provides a substantial amount of information, being the main source of subsidy data. These figures can be quite substantial as in the case of the two solar farms in NSW, the 56 MW Moree solar farm, with AU$102 million of ARENA funding in FY 2011, and the 147 MW Nyngan solar farm with AU$231 million of ARENA funding spread over FY 2015 and FY 2016. ARENA also provided AU$35 million for the 46 MW Kogan Creek solar expansion in FY 2012. Queensland state funding of AU$9 million was provided in FY 2013 for 36 MW Mackay Racecourse bagasse expansion (Mackay Sugar annual reports). ARENA also provided, and still does, funding for smaller scale projects, mostly involving new types of renewable technology. This agency has had the largest impact on renewable energy projects in recent years, but being a political body its future remains in doubt, particularly under a Coalition government which unsuccessfully sought to have it abolished in 2014.

GHG emission reductions were determined by noting the marginal generator that would be displaced through renewable energy generation being dispatched, using the same counter-factual process as used for household PV. That is because renewable energy generation has been reducing the overall level of NEM generation emissions, it is necessary to determine the level of emissions that would have occurred without renewable energy generation. This was determined by proportionately increasing the proportions of generation fuel types setting the pool price (Table 5.3).

Reduced emissions were determined by noting the generation type, being black coal-fired, brown coal-fired or gas-fired, which was not now operating. Solar operated mostly in peak periods, thereby displacing gas-fired generation, having carbon intensity factor (CIF) of 0.64 (t CO2e/MWh).

Wind generation, operating on a random basis, is assumed to displace marginal generators reflective of the NEM as a whole (CIF of 1.0 reducing to 0.70 over time, but on a counter-factual basis reducing to 0.88).

Bagasse generation is provided mostly by plants from the largest sugar mills, being those operated by Mackay Sugar and Wilmar (previously Sucrogen). These companies operate their generation plant on a 24/7 basis during and following the annual sugar crush, thereby taking advantage of higher summer pool prices and minimising stock piling of bagasse, which has combustibility risks. Hence generation displaced is likely to be that of the NEM as a whole, as in the case of wind generation.

Biomass generation arises from a range of fuel sources including land-fill gas, wood and agricultural waste, and black liquor not receiving specific grants. Like bagasse the fuel is a by-product of another process and is also assumed to displace generation reflective of the NEM as a whole.

Hydro generation occurs using both run-of-river flows and flows from dams when there is some discretion as to when hydro generation may occur. A greater proportion of hydro output could therefore be expected to occur in peak periods. It is assumed that, on average, 50% of hydro occurs in peak periods and 50% evenly spread throughout the year, being the basis for the hydro generation CIF. This produces a counter-factual CIF lower than for wind and bagasse, and higher that solar reflecting types of generation being displaced

The counter-factual CIFs used for these five types of renewable generation are shown in Table 5.3.

Table 5-3 Carbon intensity offset factors for large-scale renewable energy (t CO_2e/MWh)

	Large-scale renewables				NEM	
FY	solar	Wind	Hydro	Bagasse/Biomass	All output	Excluding renewables
2001	0.64	1.00	0.82	1.00	1.00	1.00
2002	0.64	1.00	0.82	1.00	1.00	1.00
2003	0.64	1.01	0.82	1.01	1.01	1.01
2004	0.64	1.01	0.83	1.01	1.01	1.01
2005	0.64	0.99	0.81	0.99	0.99	0.99
2006	0.64	1.00	0.82	1.00	1.00	1.00
2007	0.64	0.93	0.79	0.93	0.93	0.93
2008	0.64	0.93	0.78	0.93	0.93	0.93
2009	0.64	0.93	0.78	0.93	0.93	0.93
2010	0.64	0.88	0.88	0.76	0.88	0.88
2011	0.64	0.85	0.75	0.85	0.85	0.88
2012	0.64	0.88	0.76	0.88	0.82	0.88
2013	0.64	0.85	0.74	0.85	0.78	0.85
2014	0.64	0.85	0.75	0.85	0.76	0.85
2015	0.64	0.85	0.75	0.85	0.72	0.85
2016	0.64	0.85	0.75	0.85	0.71	0.85
2017	0.64	0.87	0.75	0.87	0.72	0.87
2018	0.64	0.87	0.76	0.87	0.71	0.87
2019	0.64	0.87	0.76	0.87	0.71	0.87
2020	0.64	0.88	0.76	0.88	0.70	0.88

Source: Energy Supply Association of Australia. (2010)

Note that CIFs have gradually reduced over time being a reflection of the higher proportion of gas-fired electricity operating at the margin, having a lower CIF than coal-fired electricity. The carbon intensity factors were applied to the output of each renewable energy type to produce annual emission reduction figures. Using the subsidy costs, mentioned earlier, produces an annual emission reduction cost (AU$/CO2e).

5.8 Non-renewable energy model approach

Non-renewable energy has been analysed broadly on an annual basis by noting the key input and output variables for each of brown coal-fired, black coal-fired, gas-fired and renewable energy, and observing trends to assist in forecasting. The analysis is not at the level of detail of household PV but this was not considered necessary as sensitivity analyses were not used. A screen shot for FY 2013 is shown in Appendix A.

Inputs for each financial year are on a AU$ per MWh basis for fuel, carbon cost (if any), capital recovery cost and total cost. Outputs are total output, emissions and the proportion of each fuel type used to set the pool price. This information is later used as input into determination of retail prices through the inclusion of renewable energy subsidies (LGCs, STCs and FITs), network charges and retailer margins.

The main purpose of the non-renewable energy evaluations is to examine how household PV reduces total electricity demand and displaces non-renewable energy, how large-scale renewable energy displaces non-renewable energy fuel sources and how demand-side management, reduces total electricity demand.

The information was also used to ensure consistency in the use of Australian-wide energy data, including consistency with total electricity production and levels of total GHG emissions. Forecasting involved noting trends in output by fuel types, to determine how expected increases in renewable energy output and DSM will input on total level of GHG emissions. In addition an evaluation was made on how carbon pricing since 1 July 2012 has impacted on fuel type output.

5.9 Demand-side management model approach – price elasticity of demand

Demand-side management is the response of electricity consumers to managing their energy usage, partly as a means of conservation and partly in response to higher electricity prices, as discussed in Chapter 4. The modelling approach attempts to quantify the impact of higher electricity prices in reducing electricity demand. Electricity is generally considered an essential item, that is having a low price elasticity of demand, but this has been changing in Australia as shown at the macro level in reduced national electricity demand since FY 2011, and at the micro level in the uptake in energy efficient appliances, household PV and battery storage. This change is likely to be magnified in future as a result of the gradual move by state, from one to two or three part pricing thereby providing market price signals for consumers to optimise their electricity usage (Burtt, 1999). As mentioned by Burtt (1999), Fan and Hyndman (2011) and Wang et al (2015) the highest level of responsiveness occurs when households experience time-of-use (TOU) or half-hourly price signals. Although consumers reduce electricity consumption for more reasons than just price increases there is little doubt that increases in real electricity prices have and will continue to impact on electricity demand. For this reason the price elasticity of demand for electricity (PEDE) has been closely analysed, firstly overseas and then in Australia.

In viewing various papers on PEDE attention has been given to more recent articles because of the more recent trend world-wide for electricity prices to increase in real terms and because of the environmental influence. In an analysis using California data over the period 1993 to 1997, Lavin, Dale et al (2001) noted that demand outcomes are affected by the possible substitution between electricity and gas, deriving a PEDE of -0.28; that is they concluded that households will materially reduce electricity consumption when prices rise while also switching between electricity and gas. The analysis by Espey and Espey (2004) is more relevant as they summarised price elasticities from other studies, concluding

> … the broad spectrum of estimates can create confusion without more detail about the differences in data and analysis techniques utilised. For example, price elasticities reported in the literature range from 0.076 to -2.01 for the short run and -0.07 to -2.5 for the long run. (Espey and Espey, 2004, p 65)

Not surprisingly PEDEs were more negative in the long-run when consumers have more time to find a more permanent electricity consumption reduction solution.

In a Chinese context Sun and Ouyang (2016) developed a model and used a data base of 10 Chinese provinces to determine a PEDE -0.387. Bonte et al (2015) examined the PEDE in the European Power Exchange for Germany and Austria over the period 2006 to 2014. A different methodology was adopted post 2009 making the almost inelastic demand pre 2009 not strictly comparable with the -0.3 to -0.9 elasticity factors post 2009. As part of their research, each of Sun and Ouyang (2016) and Fan and Hyndman (2011) examined literature on PEDE. Sun and Ouyang (2016), in a Chinese context, observing PEDEs between -0.12 and -0.50 whereas Fan and Hyndman (2011) noted PEDEs varying between -0.2 in the short run and -0.7 in the long run, for reasons given earlier.

In an Australian context, demand-price elasticities from studies 10 years ago, were noted by Narayan and Smyth (2005) as being -0.26 in the short run, and between -0.55 and -0.95 in the long run. More recently Fan and Hyndman (2011) developed two models, an annual model and a half-hourly model, to measure South Australian PEDE over the period 1997 to 2008 producing PEDE's within a -0.363 to -0.428 range. In summary, not surprisingly the PEDE tends to be higher in the long-term, following time for adjustments to occur, ranging from -0.5 to -0.9 in the long-term and from -0.3 to -0.6 in the short-term.

The objective has been to use this information to assist in viewing the reduction in electricity consumption in Australia since 2006 when electricity prices began increasing in real terms and to use the information to assist in demand forecasting. The relevance to this thesis is the fact that reduced electricity consumption means less generation output and lower emissions. The fact that part of the increase in real electricity prices is due to the inclusion of renewable energy subsidies, in the form of the two year carbon price, STC, LGC and FIT price components is evidence of a further subsidy-related emission reduction outcome.

The approach taken has been to note the increase in real retail electricity prices and to then relate this to the reduction in electricity demand. It was noted that although retail prices have been increasing in real terms it was only since FY 2010 that substantial increases have occurred. Not surprisingly consumers did not immediately react to higher tariffs but when they rose above a "trigger" level it appears they considered demand responsive action was necessary. This is reinforced by media publicity on increased tariffs, their own expenditure experiences, media publicity on energy conservation appliances and the increasingly attractive viability of rooftop PV. To avoid double counting of the demand-reduction benefit, the reduction in household demand arising from household PV has been added back to total generation demand as this emissions reduction benefit has already been evaluated in the analysis on household PV.

5.10 Model data limitations

Data used in the model analysis is almost entirely from public sources for financial years ending June. Cross checks were undertaken to ensure outcomes aligned with information reported in the media. For example FITs and the number of installations by state were compared with state announcements of FIT costs, and the number of STCs arising from number of installations was found to align with numbers of STCs, excluding those for solar hot water systems, reported by the Clean Energy Regulator.

The limitations of this research relate mainly to the conversion of some annual data to FY data such as FITs by state. Various cross checks were undertaken, for example in regard to total FIT payments by state, to ensure approximations were realistic. Estimates of annual network costs, for inclusion in retail electricity costs were also undertaken using information from a range of sources including the AER and AEMO. FIT costs were deducted from network costs so that network costs did not include any subsidy components.

The annual generation mix required the addition of Western Australia and Northern Territory figures to National Electricity Market (NEM) data. This information is used to examine the switch from coal-fired to gas-fired electricity generation during the two year carbon price period but their impact is of a minor nature.

Measuring the level of reduced GHG emission reductions from renewable energy generation required a counter-factual approach, that is noting which generators were operating and setting the pool price each half hour to determine how emissions would have been reduced when replaced by renewable energy. This analysis was undertaken in substantial detail for 2012 with the same mix of coal and gas-fired generation assumed to exist in other years. This approximation is not crucial as it relates to the entire year and not individual half-hours.

Chapter 6 Model results

Summary

Chapter 6 discusses the outcome of modelling Australian household PV including the sensitivity of the emission reduction results to changes in input data. The household PV analysis is then extended to include the economics of adding battery storage. The effect of subsidies on large-scale renewable energy output and emission levels, by renewable energy type, is then combined with household PV results to provide a total renewable energy picture. How non-renewable energy is affected by renewable energy developments is also examined. The chapter concludes with an analysis of the effect of increases in real retail electricity prices on reduced electricity demand.

The results should be seen in the context of data accuracy, with FITs requiring the greatest level of approximation followed by large-scale renewable energy capital costs and LGCs created by large-scale renewable energy (see also Section 5.10). These data have however been compared with related information to ensure they are broadly accurate, as mentioned in the Appendices.

The results of analyses such as this involving small date sets is subject to greater variation in outcomes often resulting instead in Monte Carlo or simulation models. The close relationship between the variables being examined suggests other approaches may not be necessary but the outcome, for this reason still needs to be treated with caution.

6.1 Household PV model results and PV forecasts

The household PV model is used to determine financial viability, measured by payback periods, and then to determine the relationship and sensitivity between financial viability and new PV capacity, measured in MW. This relationship is examined over FYs 2006 to 2014, then forecast to 2020, with the results summarised in Table 6.1 and portrayed in Figure 6.1. The nine year period is comparatively short for regression analysis, lending itself more to other forms of analysis such as but the relationship is strong; nevertheless the results need to be treated with some caution.

The model allows the various inputs into payback periods, such as household electricity prices, FITs, STC prices and STC multipliers, to be changed producing sensitivity analyses on payback periods. Payback periods were then able to be converted into associated levels of actual PV, which in turn were used to determine reductions in levels of GHG emissions, so that the relationship was then established between household PV financial inputs and resultant levels of emission reductions.

There are only a small number of data weaknesses, including the conversion of some calendar year data into financial year (ending 30 June) data and evaluating the time delay between when states announced FIT termination dates and the time taken for households to actually have PV installed. This was accommodated in the model by having a six month lag between payback periods and PV installation dates. Lags of periods greater and shorter than six months were also tested but six months, used consistently over the nine years, provided the best "fit".

Table 6-1 PV payback periods

Financial year	PV capacity (MW)	Payback (years)	Payback post lagging (years)
2006	2	47.4	47.4
2007	6	43.4	45.4
2008	23	32.5	38.0
2009	56	16.1	24.3
2010	227	5.4	10.7
2011	600	3.3	4.4
2012	901	2.8	3.1
2013	860	3.9	3.4
2014	662	4.3	4.1

Source: PV capacities from Green Energy Markets (2014a)

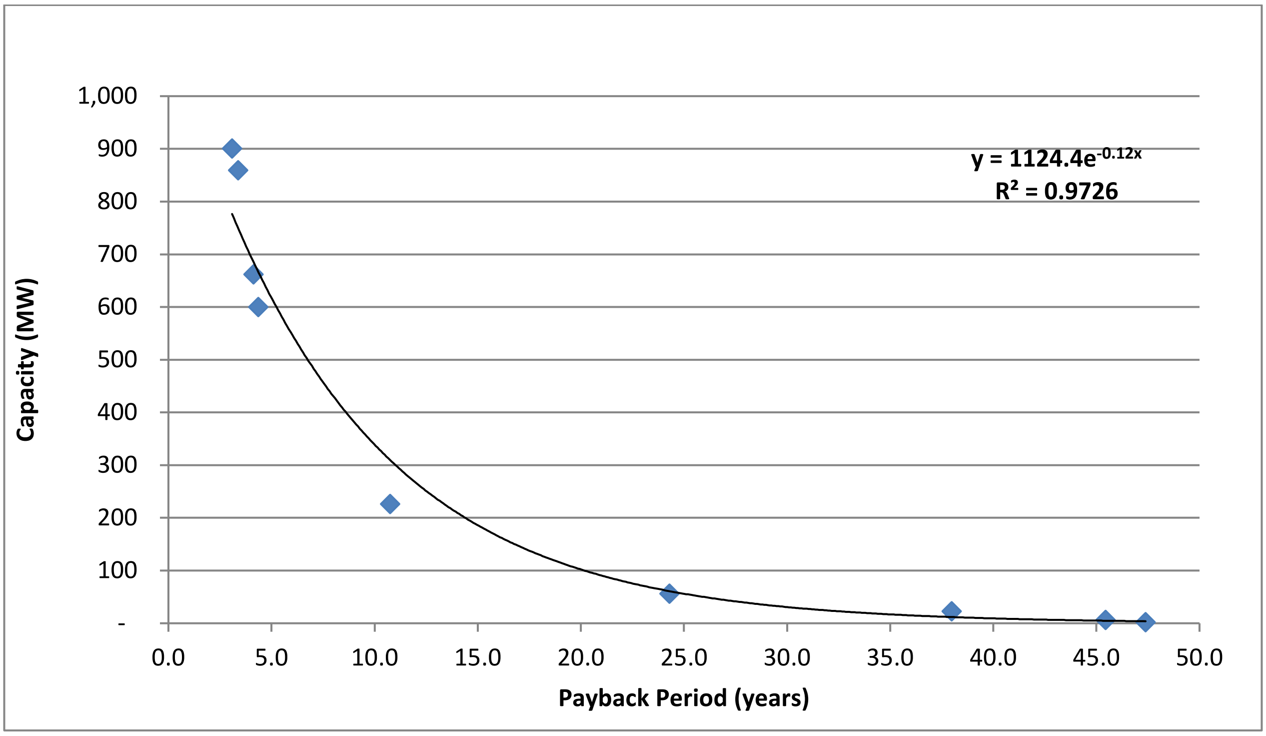

Figure 6-1 Relationship between payback periods and new PV capacity

The four years of most growth, since FY 2010, have payback periods of less than five years. More recent data suggests payback periods will soon exceed five years, reflecting reduced FITs and expectations that household electricity price increases may not be as great in future. These payback period results are similar to those contained in ACT Government (2015).

6.1.1 *Household PV forecasts and emission costs per tonne of CO_2e*

Household PV has been forecast to 2020 using forecasts from Green Energy Markets (2014a) to FY 2016. Forecasts beyond 2016 are derived by assuming PV panel costs increase gradually to AU$2/watt in 2020, new PV system sizes remain at 3.4 kW, as used in Green Energy Markets (2014a) forecasts, STCs remain at their current price of AU$37/STC, FITs covering only the non-subsidised retailer payment of an average AU8c/kWh and retail electricity prices built up by individual components (Table 7.9). These assumptions produce model-related payback periods increasing gradually to between five and six years by FY 2020.

The weakness in this approach is that there will be increasing resistance from non-PV households who were not able to be enticed to install PV when payback periods were nearly half what they are now and there is a physical uptake limit due to the finite number of houses in Australia regardless of how attractive the economics may be. Queensland and South Australia had reached penetration rates of 22% and 25% as at December 2013 (SunWiz, 2013) with Australia as a whole at 14% (Parkinson, 2013). AEMO (2012) used a 75% saturation uptake rate in their Australian rooftop PV forecasts, being higher than has been modelled, a view shared by Williamson (2016).

These factors have been accommodated by reducing the model-determined output by 10% in FY 2017, 20% in FY 2018, 30% in FY 2019 and by 40% in FY 2020. This assumption could be an over-reaction so model-determined output reductions of 7% in FY 2017, 14% in FY 2018, 21% in FY 2019 and 28% in FY 2020 were also examined. The two scenarios are shown in Table 6.2 under “Base forecast” and “Optimistic forecast” respectively.

Table 6-2 Household PV forecasts under different saturation factor assumptions

	Base forecast				Optimistic forecast			
	Annual uptake	Accum. uptake	Annual output	Accum. Output	Annual uptake	Accum. uptake	Annual output	Accum. Output
FY	(MW)	(MW)	(GWh)	(GWh)	(MW)	(MW)	(GWh)	(GWh)
2006	2	2	2	2	2	2	2	2
2007	6	8	8	10	6	8	8	10
2008	20	30	30	40	20	30	30	40
2009	60	90	70	110	60	90	70	110
2010	230	310	290	400	230	310	290	400
2011	600	910	770	1,170	600	910	770	1,170
2012	900	1,820	1,150	2,320	900	1,820	1,150	2,320
2013	860	2,680	1,100	3,420	860	2,680	1,100	3,420
2014	660	3,340	850	4,260	660	3,340	850	4,260
2015	570	3,910	730	4,990	570	3,910	730	4,990
2016	560	4,460	720	5,700	560	4,460	720	5,700
2017	530	5,000	680	6,380	550	5,010	700	6,400
2018	460	5,460	590	6,970	500	5,510	640	7,040
2019	400	5,860	510	7,480	450	5,960	580	7,620
2020	330	6,190	420	7,910	400	6,360	510	8,120

Note: non-single figures rounded to nearest 10.

The sensitivity analysis of less saturation resistance suggests that by FY 2020 an extra 170 MW of capacity would be installed, being an extra 210 GWh of output pa. The base forecast, which is very similar to that of AEMO (2015b) over the period FY 2015 to FY 2018 (of 6,950 GWh in FY 2018), is equivalent to a household penetration rate increasing from 14% in late 2013 to 21% in FY 2020, that is 2.1 million installations out of an expected 10.0 million households (Australian Bureau of Family Studies, 2014).

Household PV capacity is forecast to reach 6,190 MW, equivalent to 7,910 GWh pa (Table 6.3). This is higher than most other forecasts (Sunwiz, 2012; AEMO, 2012), most likely because other forecasts were made prior to the strong continuing growth in household PV in FY 2013 and FY 2014. This is supported by the more recent forecasts of Green Energy Markets (2014b) which are marginally higher than those forecast in this thesis, mainly because Green Energy Markets (2014b, page 6) assume little withering, that is reducing household penetration. Forecasts by Oliva and MacGill (2013), assuming different FIT assumptions, are consistent with the forecasts developed in the model when viewed at the higher end if FIT assumptions. More recent AEMO research suggests that the FY 2020 forecast could be conservative, highlighting the variations in forecasts (AEMO, 2016).

Table 6-3 Household PV output, emissions and associated costs

Financial year	Total solar output	Solar emission reductions	Subsidy Cost	Amortised subsidy unit cost	Total elec. Emissions
	(GWh pa)	(t $CO_{2\ pa}$)	(AU$thous)	(AU$/t $CO_{2\ pa}$)	(t $CO_{2\ pa}$)
2006	2	2,110	$730	$9	212,350,800
2007	10	9,230	$1,430	$18	219,832,780
2008	40	34,800	$10,320	$35	220,074,720
2009	110	97,050	$60,300	$71	225,834,740
2010	400	349,020	$708,470	$212	223,869,740
2011	1,170	1,016,390	$1,093,340	$174	219,107,220
2012	2,320	2,017,710	$1,199,240	$144	216,957,560
2013	3,420	2,973,290	$853,650	$125	205,746,400
2014	4,260	3,709,580	$703,730	$118	199,186,720
2015	4,990	4,341,140	$685,870	$116	198,100,000
2016	5,700	4,963,150	$680,730	$114	202,920,000
2017	6,380	5,553,470	$566,890	$112	203,560,000
2018	6,970	6,069,310	$471,240	$112	203,560,000
2019	7,480	6,512,880	$449,590	$109	203,560,000
2020	7,910	6,879,750	$421,860	$110	203,560,000
Total	51,170	44,528,880	$7,907,380		

Note: non-single figures, except subsidy unit costs, rounded to nearest 10.

Source: ARENA, Green Energy Markets (2014b)

Table 6.3 highlights the high cost of subsidies in FYs 2011 and 2012, exceeding AU$1billion each year. The costs are higher a year earlier on a emissions reduction unit basis because of the increasing average size of installed units. STC subsidies apply only to the first 1.5 kW so that as average sizes increased, from 1.7 kW in FY 2010, to 2.2 kW in FY 2011 to 2.6 kW in FY 2012, the extra output is not associated with extra STC subsidy costs.

Household PV emission reduction costs

Most papers addressing the cost of reducing GHG emissions, including Bakhtyar (2014), view costs on a per tonne of CO_2e in the year concerned. This does not recognise the fact that PV subsidies provide emission reduction benefits well beyond subsidy cost years. This necessitated subsidies being allocated over future emission reduction years to determine effective annual subsidy costs. The Australian Government Productivity Commission undertook such an analysis assuming an economic life of 20 years and applying a discount rate of 7% (Australian Government Productivity Commission, 2011, p 10). As PV systems may have an economic life in excess of 20 years and because the results could be sensitive to the discount rate used, scenarios of 20 and 35 year terms and discount rates of 5%, 7% and 10% have been used to determine effective annualised emission benefits (Table 6.4).

Table 6-4 Discount rate and term sensitivity of annualised emission reduction costs from household PV in Australia between 2007 and 2020 (AU$ per t CO_2e)

Discount Rate	5%	5%	**7%**	7%	10%	10%
Term (Years)	20	35	**20**	35	20	35
2007	15	12	**18**	15	22	20
2008	30	23	**35**	29	43	38
2009	60	46	**71**	58	88	77
2010	180	137	**212**	173	263	232
2011	148	113	**174**	143	217	192
2012	122	93	**144**	118	179	158
2013	106	81	**125**	102	155	137
2014	100	76	**118**	96	147	130
2015	98	75	**116**	95	144	127
2016	97	74	**114**	93	142	125
2017	95	72	**112**	92	139	123
2018	93	71	**112**	90	137	121
2019	93	71	**109**	89	136	120
2020	93	71	**110**	90	136	120
Average	95	72	**112**	92	139	123

The benchmark of 20 years and a 7 % discount rate resulted in effective emission costs peaking at AU$212 per t CO_2e in 2010 decreasing to a steady AU$110 per t CO_2e, and averaging AU$112 per t CO_2e over the 14 year period. Increasing the term to 35 years and reducing the discount rate to 5% reduced average emission costs to AU$72 per t CO_2e. At the other extreme of a 20 year term and 10% discount rate, average emission costs increased to AU$139 per t CO_2e, thereby highlighting the sensitivity of emission reduction unit costs to the term and discount rate used.

6.1.2 *Sensitivity of model results*

The model has been used to analyse how payback periods change when inputs such as the cost of solar, FITs and household electricity prices change. Changes in resultant payback periods are then used, based on the relationship shown in Figure 6.1, to determine expected changes in installed PV and consequent GHG emission reductions.

The sensitivity analysis examines the nine year period from FY 2006 to FY 2014, when most PV activity occurred. It is important to note that when payback periods are low a small change in the payback period gives rise to a substantial uptake in household PV (Figure 6.1). This was also noted by Antonelli and Desideri (2014) who commented "A comparison among different EU countries showed that FITs push the market to significant levels only when they are high enough" (Antonelli and Desideri, 2014, p 583).

For policy purposes this means that extra incentives are most effective when almost all financial factors are also favourable; hence the high PV uptake in FY 2012. On the other hand the Australian Government Productivity Commission (2011, p. 83) concluded that FITs and STCs were providing duplicating and therefore excessively costly incentives which together did not provide any additional emission reduction benefits.

6.1.3 *Effect of increasing the cost of household PV*

PV unit costs in Australia are likely to increase in future because the world-wide solar panel supply overhang will eventually correct itself; however this has yet to be apparent in Australia despite the reduction in the value of the Australian dollar in the last two years.

If the average cost of installed PV, net of the STC benefit, had been 20% higher over the nine year period the volume of PV would have been 15% lower, that is 2780 MW compared with 3270 MW. An extreme situation was also examined by assuming PV costs had not reduced over time but remained at AU$8,000 per kW from FY 2006 to FY 2014, rather than falling to AU$1,500 per kW. The outcome was that over the nine year period household PV would have totalled 790 MW rather than 3270 MW, a reduction of 76 %, suggesting that most of the uptake of PV was due to the declining cost of PV rather than consumer subsidy incentives.

6.1.4 *Effect of lowering the STC price*

In Australia, a review of the LRET in 2015 resulted in a reduction in the LRET 2020 target but small-scale renewable projects, impacted by STCs, were not affected. Nevertheless a change in legislation could occur and so some sensitivity runs were undertaken. Since FY 2006 the STC price has been comparatively stable, varying between AU$35 and AU$40/STC reflecting the comparatively short quarterly STC acquittal period and the AU$40/STC price cap. A material change to the price cap would need to occur for there to be a noticeable change to household PV uptake.

A sensitivity run was undertaken with STC prices being AU$10/STC lower, being an average 28 percent price reduction. The outcome was PV capacity reducing by 8% from 3270 MW to 3010 MW over the nine year period. Another possibility is that legislation is altered so that retailers no longer had an STC liability, resulting in a model run being undertaken with STCs having a zero price and FITs at current historically low levels. The outcome was that for FY 2014 the payback period increased from 4.3 years to 5.7 years, suggesting that, in this extreme example, households will continue to have an interest in installing PV.

6.1.5 *Effect of reducing the STC multiplier*

The STC multiplier, producing additional "deemed" STCs not reflective of actual output, came into effect during FY 2010 and ended in 2013, resulting in the creation of an additional 65 million STCs over the four year period, having a market value of AU$2.2 billion, indicating the substantial subsidy that was involved (and paid for by all electricity consumers). If no deeming had existed and the multiplier remained at unity for each year, PV uptake would have been 2740 MW rather than 3270 MW, a decrease of 530 MW or 16% over the four year period. This is almost twice the impact that would have occurred if STC prices had been reduced by AU$10 per STC.

6.1.6 *Effect of reducing feed-in-tariffs*

States and territories introduced attractive FITs in FY 2009 and FY 2010, being phased out in FY 2013. Some FITs were briefly reduced to AU8c/kWh for new installations post FY 2013 which was used for a model run. Over the five year period household PV uptake would have been 550 MW lower, that is 2720 MW rather than 3270 MW, a reduction of 17 percent. This reduction is not as great as might have been expected from high FITs, and so a further sensitivity run was undertaken with all FITs set at zero. The outcome was a reduction of 1060 MW or 33%. Expressed another way 67% of PV uptake would have occurred had there been no FITs.

6.1.7 *Effect of lowering household electricity tariffs*

Household electricity prices have been increasing in real terms for nearly 10 years. The higher this increase the more attractive it is for households to install PV to reduce their domestic power bills. This is one of the main reasons why there continues to be a strong interest in PV even though retailer payments are only for retailer avoided energy costs of AU6c/kWh AU8c/kWh.

A model run was undertaken with household electricity prices increasing by 2.5% pa from FY 2006 to FY 2013, approximating being constant in real terms, compared with higher actual retail tariffs averaging 11% pa over this period (Energy Supply Association of Australia, 2013). The outcome was that PV uptake would have been 234 MW lower, at 3030 MW compared with 3270 MW (a decrease of 7%).

The sensitivity results are summarised in Table 6.5.

Table 6-5 Summary of model sensitivity results from FY 2006 to FY 2014

Input Variable	Input Change	Changes in PV output and emissions		
		Percentage	MW	GHG increase (t CO_2e)
Cost of PV	Increased by 20%	15% lower	490	566,000
Cost of PV	Fixed at FY 2006 price	76% lower	2470	2,845,000
STC price	AU$10/STC lower	8% lower	260	299,000
STC multiplier	Fixed at unity	16% lower	530	554,000
FITs	Fixed at 8c/kWh	17% lower	550	629,000
FITs	Zero FIT	33% lower	1060	1,224,000
Household tariffs	Constant in real terms	7% lower	230	273,000

6.1.8 *Sensitivity of hours of solar offset and export*

The assumptions of an average 2.0 h per day for domestic consumption offset and 1.5 h per day export for Australia as a whole were reviewed. If export hours were held constant at 1.5 hours per day and consumption offset hours initially increased and then decreased by 0.5 h per day the outcome would be emission unit costs decreasing by 12 % and increasing by 16% respectively. This is because the total level of subsidy would not change, as STCs are based only on the first 1.5 kW of output and exported energy does not change. However with increased consumption offset hours the level of emission reductions is increased resulting in lower emission unit costs, and conversely for reduced consumption offset hours.

If instead consumption hours are held constant and export hours initially increased and then decreased by 0.5 hours per day the outcome would be emission unit costs increasing by 9% and decreasing by 12% respectively. The former reflects the subsidy level increasing by more than the increase in export emission reductions, and conversely for the latter. The outcomes are not more extreme as in all four examples subsidy costs and emission reductions change in the same direction.

6.1.9 *Energy storage developments world-wide*

Although not part of the modelling in this thesis there is the potential for PV to provide substantial market benefits in the wholesale market through the storing of excess electricity at times when wholesale electricity prices are low for later exporting to the grid at times of high (peak) prices. This is currently exhibited mostly in the form of pumped storage, whereby water is pumped uphill to a catchment area to be later released, to flow through hydro-turbines at times of high electricity prices (IEA, 2014a). Similar energy storage benefits are not yet able to be achieved in the retail market as households generally experience one-part tariffs, not showing variations reflective of wholesale electricity prices. Furthermore households in most Australian states do not have time-of-use meters (Burtt, 2009) and the cost of storage is prohibitive (Mayr et al, 2014). However battery storage costs are rapidly declining. Edis (2014) summarised results from seven authors showing the cost of battery storage had declined by an average 40% between 2011 and 2014, with a further reduction of 35% expected between 2014 and 2020. In a Japanese context Komiyama and Fujii (2014) concluded that better use of LNG combined cycle plant and lower battery costs were necessary to secure the full potential of PV. Offsetting the improving economics of battery storage is the development of network companies, in an endeavour to protect revenue levels, to increase the fixed charge tariff component and reduce the variable charge component. This reduces the avoided costs associated with consumers becoming less reliant on imported electricity. This is a recent development and has not been modelled.

Chiang et al (1998) examined the most efficient relationship between household PV output and household consumption with a battery storage system, to determine how to most cost-effectively satisfy a utility's power requirements. An experimental 600 watt system was used concluding that although set-up costs made the proposal uneconomic this could change in the future. Zahedi (2011) provided similar comments particularly in regard to the value of energy storage in improving overall PV reliability.

The increasing focus on energy storage has prompted research into the most efficient types of battery systems. Yang et al (2011) examined the technical efficiency of a wide range of electrochemical battery types concluding that "the applications in terms of capacity, siting, performance parameters, etc. need to be further refined" (Yang et al, 2011, p. 3605). Hu et al (2014) examined three energy storage systems, a Li-ion battery, a supercapacitor pack and a combination of the two to determine which choice was most cost effective in powering a hybrid powertrain, concluding that in general the hybrid option was most cost effective but the outcome could vary depending on battery and diesel costs. Utilisation of used electric vehicle batteries is seen by Heymans et al (2014) as a valuable energy storage option, possibly not immediately but in the future as usage of electric motor vehicles increases world-wide. The inclusion of cost-efficient battery storage with household PV increases the likelihood that households will at some time in the future disconnect from the grid, with utilities seeing this as a threat requiring a review of their business models (Rocky Mountain Institute, 2014). This could become a real challenge for network companies world-wide in the near future.

6.1.10 *Economics of household energy storage post expiry of FITs*

There is the potential to extract more value from household PV through storing excess PV and utilising this output to reduce electricity costs. At times when households are still benefitting from attractive FITs this is unlikely to be the most economic option, because households can earn more from FITs compared with saving from reduced electricity imports. Hence the evaluation in this section is for 1. households with existing PV but only able to obtain the lower retailer avoided cost of AU8c/kWh and 2. households without PV looking to install both PV and battery storage. The economics will be less favourable in the case of 2. as capital costs of both PV and battery storage are involved. The main reason for the increasing interest in battery storage reflects the continuing decline in the cost of lithium-ion batteries, in a similar manner to the increasing interest that occurred in household PV in 2009 and 2010. The cost reductions are first being experienced in USA and are expected to be experienced in Australia in the near future (Parkinson, 2015).

The evaluation is undertaken from the point of view of households having the load profile and PV output profile referred to in Section 5.7. These features are those of an average Australian household and will therefore be indicative only given variations in factors such as levels of household consumption, electricity tariffs, and efficiency of PV panels, reflective of geographical location.

As mentioned above the economics of battery storage are least favourable when households have attractive FITs, and also when they experience flat tariffs. The outcome improves when attractive FITs are no longer available and when electricity tariffs show some reflection of wholesale market prices, such as three part tariffs as exist in NSW. AEMO (2015a) noted this in predicting that for this reason the highest growth in battery storage in Australia would be in NSW (AEMO, 2015a, p 4). If electricity tariffs are restructured and continue to increase in real terms, while energy storage costs continue to decline, the economics of household energy storage will become increasingly attractive. Hence the analysis has relevance for both today and the future.

A comparatively simple model, based on data used in previous sections, has been developed to show the cost impact from various sizes of battery and the associated economics.

The 2 kW PV example in Table 6.6 reflects data contained in Figure 5.6, being on an hourly basis, with the addition of larger sizes of PV units. The level of export to the grid clearly increases while the level of domestic offset only marginally increases; the reason being that it is only at the start and end of the solar output period that increased solar size (marginally) reduces domestic consumption. The important feature of Table 6.6 is that for a 2 kW system the level of exports (2.90kWh/day), if stored rather than exported, only reduces imported electricity from 17.80kWh/day to 14.90 kWh/day, on average. To avoid having to import any electricity from the grid the PV system would need to be at least 7 kW, shown by the export volume being

2.60kWh/day in excess of import requirements, the 2.60kWh/day being a buffer necessary to accommodate day-to-day fluctuations. In reality the buffer would probably need to be even greater than this to avoid occasional blackouts while still requiring close monitoring of daily consumption in case some demand-side management is still required.

Table 6-6 Household PV output relationship to household consumption

H/Hold consumption		Solar output		Domestic	Excess export	Import from	Import from grid
annual	daily average	size	daily average	offset	to grid	grid	less exports
(kWh pa)	(kWh per day)	(kW)	(kwh)	(kWh/day)	(kWh/day)	(kWh/day)	(kWh per day)
8,000	21.92	2.0	7.0	4.13	2.87	17.79	14.92
8,000	21.92	4.0	14.0	4.53	9.47	17.39	7.92
8,000	21.92	6.0	21.0	4.77	16.23	17.15	0.92
8,000	21.92	7.0	24.5	4.82	19.68	17.10	-2.58

Source: Figure 5.6

The economics of the options in Table 6.6 are shown in Table 6.7.

Table 6-7 Household energy storage viability

PV	Import savings, not	Battery	Battery		Payback period with existing solar		Solar system	Payback period with new solar	
size	exporting	Storage	cost		low batt. cost	high batt. cost	costs	low batt. cost	high batt. cost
(kW)	(AU$ pa)	(kWh)	low (AU$)	high (AU$)	(years)	(years)	(AU$)	(years)	(years)
2.0	283	3 kWh	$3,500	$7,000	12	25	$2,700	9	14
4.0	933	10 kWh	$5,000	$10,000	5	11	$6,700	8	12
6.0	1599	17 kWh	$6,500	$13,000	4	8	$10,700	8	11
7.0	1939	20 kWh	$7,000	$14,000	4	7	$12,700	8	11

Source: Parkinson (2015), Dolev (2015)

The import savings from using stored electricity need to be matched against the cost of battery storage and, where households do not already have solar, the combined cost of battery storage and new PV costs (Table 6.7). The same approach to viability as discussed in Section 5.7.1, that is the payback number of years, has been used. There is substantial variability in gross battery costs, conversion of costs from US dollars to Australian dollars, and the ongoing decline in battery costs. For this reason an upper and lower level of battery costs has been included. The USA company Tesla is the world leader in lithium-ion batteries, manufacturing them principally for electric motor vehicles. Tesla's soon-to-be–opened Gigafactory in Nevada is, according to Dolev (2015), expected to reduce a 60 kWh Tesla battery from US$250/kWh to US$88/kWh with the outcome being that "battery prices are dropping faster than anyone ever expected".

For households already with PV the payback period is comparatively high if their PV is the most common size of 1,500 to 3,000 watt, being at least 12 years. The payback period falls substantially for households with PV systems in excess of 4kW because PV exports increase at a proportionately faster rate with PV system size, and battery costs exhibit substantial economies of scale. Although the payback period is currently about 11 years it is expected to eventually fall to nearly four years. Based on the experience with household PV a four year payback period will result in a substantial uptake of battery storage systems. Unlike household PV this mini boom is not driven by subsidies, although subsidies were largely responsible for the initial household PV boom.

These results are consistent with those in AEMO (2015a) and those of Vorrath (2015) who commented on a report by UBS entitled "UBS: Battery storage payback for solar households will be 5-6 years by 2020" highlighting the over 50% decline in lithium-ion battery costs and expectations of a four year payback period by 2020 for households with PV and an eight year payback period for those without PV.

For households without PV, without the advantage of sunk PV costs, payback periods are currently at least 11 years but are expected to fall to 8 or 9 years. Based on experience with household PV the uptake is unlikely to be substantial. However if retail tariffs continue to rise in real terms and battery storage costs decline faster than anticipated, payback periods may drop to levels where households will show an active interest.

An additional factor is the life-cycle of batteries with Khalilpour and Vassallo (2016) noting that Lithium-ion batteries have a 10 year life span. This does not become a critical factor as it is unlikely decisions to install battery storage would be taken where the payback period exceeded 10 years. As well as economics being the driver of the interest in battery storage there is also the desire by some households to be independent of electricity from the national grid, that is to go "off-grid". This may not be quite as simple as some households imagine, because they are likely to still want electricity 24 hours a day and there will be times, in overcast conditions, when little power is being stored resulting in batteries having no charge. Choices then are to install much larger PV systems and have much larger batteries, which will test the strength of the desire to go off-grid to avoid paying network standing charges.

6.2 Large-scale renewable energy model results

The large-scale renewable energy model involves substantial detail so only result summaries have been reproduced. Detail not shown relates to determination of payback periods, involving plant capacity, operating hours pa, capital costs, revenue from LGCs, grants and exports to the grid. A key model input into the viability of large-scale renewable energy is revenue from LGCs. LGC prices have risen sharply since early 2015 and are assumed to remain between AU$60/LGC and AU$70/LGC (Figure 5.10).

Large-scale renewable energy forecasts are based on BREE (2015). Forecasts have been determined by viewing proposed projects at the approved stage contained in Energy Supply Association of Australia (2014) for the period FY 2016 to FY 2020. Projects averaged 860 MW pa for wind and 100 MW pa for large-scale solar with 30 MW pa for bagasse. On a conservative basis, capacity for the five years to FY 2020 was forecast at 500 MW pa for wind and 100 MW pa for large-sale solar. They were not considered overly optimistic by Rose (2015) and, as the results suggest, indicate that the LRET target is likely to be met. This is not surprising as achieving the LRET target is close to being a self-fulfilling prophesy because if this were not the case the LGC price would trade at the tax-adjusted penalty price (of AU$92.86/MWh) being sufficient to ensure viability of the required projects that generate this outcome. The key variations would be (project delayed) timing, in which case the target might be met after 2020 and over-shooting, mainly due to growth in unexpected household PV. Details on how output figures and payback periods for each renewable energy type were determined are contained in Appendix A.3.

The approach taken to determine how subsidies have stimulated renewable energy was to note, for each large-scale renewable energy type, the baseline reported by CER, with this output level deducted from actual output each year. This difference should replicate the level of LGCs created by each renewable energy type each year, but this was not always the case due to timing differences and the possibility of unreported generation (such as off-grid generation) as suggested by CER. Hydro energy results differed the most from expectations, which is discussed further in the hydro energy section that follows.

Subsidy costs are shown as costs that arose in the year of expenditure except for grants that have been amortised over future years, in effect spread over the years in which the emission reduction benefits occur, as was undertaken with household PV. A minor disadvantage of the amortised approach is that costs are spread over the 20 years that follow so that at the end of the 20th year these costs will terminate. Results for individual fuel types exhibit some volatility so ideally the results should be viewed for renewable energy as a whole.

There is a small timing mismatch relating to the period of analysis being the 20 year period from FY 2001 to FY 2020. The RET scheme began on I January 2001 and the emission reduction and renewable energy target periods are from calendar year 2001 to calendar year 2020. Therefore the analysis covers a 20 year period starting and ending six months earlier than the legislated period. The availability of most data is on a financial year basis and the difficulties of having a half year adjustment at the start and end of the analysis period meant that a timing change was not justified. This is not considered a major concern.

There are two aspects that impact on the results for each of the renewable energy types. Firstly emission reduction benefits are calculated by comparing the carbon intensity factors (CIFs) of the generation displaced with the much lower renewable energy CIF. Over time coal-fired generation is being replaced by gas-fired generation and renewable energy so the CIF of the NEM as a whole is declining (discussed in more detail in Section 5.7.2). This in effect increases renewable energy unit emission costs and is the main reason why these costs increase towards FY 2020. Secondly the large increase in LGC prices in FY 2008 and FY 2015 (Figure 5.10) has resulted in a material step-wise increases in emission reduction unit costs. In reality renewable energy producers are likely to have secured fixed price LGC (and energy revenue) prices for at least three years so the trend may not be exactly as shown.

6.2.1 *Large-scale solar energy model summary*

Large-scale, being non-household, solar energy has shown sustained growth due mostly to the 56 MW Moree Solar farm in NSW, the 46 MW solar thermal booster to the Kogan Creek power station in Queensland and the 147 MW Nyngan solar plant in NSW (Table 6.8). There are also a range of solar projects varying from 10 MW to 60 MW. Grants have been associated with each of these large-scale projects which also receive subsidies relating to LGCs, credited for each MWh of output

The cost of emissions increased substantially in FY 2012 as a result of grants associated with the large-scale projects previously mentioned. On an amortised cost basis, unit reduction costs rose to over AU$200/t CO_2e but are forecast to decrease to AU$130/t CO_2e by FY 2020, reflecting rapid output growth over which costs are allocated.

Table 6-8 Non-household solar generation output, subsidy costs and GHG emission reductions

FY	Output (GWh pa)	Total GHG emissn redns (thous t CO_2e)	Subs. related output (GWh pa)	Subsidy rel'd emissn redns (thous t CO_2e)	Subsidies, grants (AU$thous)	GHG redn subsidy cost (AU$/t CO_2e)	Amortized cost (AU$/t CO_2e)
2001	50	0	0	0	$0	$0	$0
2002	60	0	0	0	$10	$57	$57
2003	60	0	1	0	$20	$59	$59
2004	70	1	1	1	$40	$60	$60
2005	80	1	1	1	$50	$54	$54
2006	90	1	2	1	$40	$38	$38
2007	90	1	2	1	$50	$41	$41
2008	80	1	2	1	$110	$78	$78
2009	40	1	2	1	$120	$83	$83
2010	20	2	4	2	$140	$63	$63
2011	360	3	5	3	$190	$60	$60
2012	240	8	10	8	$11,820	$1,468	$193
2013	400	40	70	40	$67,970	$1,642	$230
2014	590	80	120	80	$51,630	$660	$199
2015	730	150	230	150	$101,060	$698	$205
2016	940	250	390	250	$174,710	$707	$236
2017	1,180	360	580	360	$34,490	$95	$191
2018	1,710	670	1,060	670	$63,620	$95	$147
2019	2,020	830	1,320	830	$78,950	$95	$137
2020	2,320	990	1,570	990	$94,280	$95	$130
Total	11,140	3,380	5,370	3,380	$679,290	$6,150	

Note: non-single figures, except subsidy unit costs, rounded to nearest 10.

Source: IRENA (2015), AEMO Annual Statements of Opportunities, Energy Supply Association of Australia annual reports, Research paper to Australian Parliament 2001, Clean Energy Regulator (2015), Australian Government, Department of Industry and Science (2015a), AEMO (2015b).

6.2.2 *Wind energy model summary*

Wind generation has, and is expected to continue to show most growth of any renewable energy type. Wind energy forecast output assumes 500 MW of new wind generation each year from FY 2015 to FY 2020 reflected in Table 6.9. Following the hike in LGC prices in mid 2015, this growth now appears achievable. This forecast may be over-optimistic but large-scale solar installations have been conservatively forecast suggesting that large-scale renewable energy output forecasts are best viewed in aggregation. Further information on how output figures were determined is contained in Appendix A.3.

The cost of wind emissions is comparatively low, averaging AU$40/t CO_2e to AU$50/t CO_2e, because there are few grants provided for wind projects. The only material subsidies are from

LGCs which, combined with substantial output growth, has resulted in amortised unit emission reduction costs forecast to increase to a comparatively low AU$73/t CO_2e (Table 6.9).

Table 6-9 Wind energy output, subsidy costs and GHG emission reductions

	Output	Total GHG emissn redns	Subs. related output	Subsidy rel'd emissn redns	Subsidies, grants	GHG redn subsidy cost	Amortized cost
FY	(GWh pa)	(thous t CO_2e)	(GWh pa)	(thous t CO_2e)	(AU$thous)	(AU$/t CO_2e)	(AU$/t CO_2e)
2001	230	220	220	210	$8,060	$38	$38
2002	350	330	340	320	$12,200	$38	$38
2003	670	640	670	640	$24,700	$39	$39
2004	740	710	730	710	$27,860	$39	$39
2005	900	850	900	840	$30,510	$36	$36
2006	1,690	1,610	1,690	1,600	$40,460	$25	$25
2007	2,680	2,360	2,670	2,350	$69,450	$30	$30
2008	3,660	3,210	3,660	3,210	$179,180	$56	$56
2009	3,360	2,950	3,350	2,950	$174,400	$59	$59
2010	4,980	4,150	4,970	4,150	$198,830	$48	$48
2011	5,800	4,670	5,790	4,660	$220,100	$47	$47
2012	5,960	4,930	5,950	4,930	$226,130	$46	$46
2013	7,640	6,100	7,630	6,100	$259,540	$43	$43
2014	10,280	8,250	10,270	8,240	$308,170	$37	$37
2015	13,210	10,570	13,200	10,570	$527,990	$50	$50
2016	14,850	11,950	14,840	11,940	$890,530	$75	$75
2017	16,490	13,500	16,490	13,500	$989,080	$73	$73
2018	18,130	14,890	18,130	14,890	$1,087,630	$73	$73
2019	19,780	16,280	19,770	16,280	$1,186,180	$73	$73
2020	21,420	17,680	21,410	17,680	$1,284,730	$73	$73
Total	152,800	125,840	152,680	125,740	$7,745,740		

Note: non-single figures, except subsidy unit costs, rounded to nearest 10.

Source: IRENA (2015), AEMO Annual Statements of Opportunities, Energy Supply Association of Australia annual reports, Research paper to Australian Parliament 2001, Clean Energy Regulator (2015), Australian Government, Department of Industry and Science (2015a), AEMO (2015b).

6.2.3 *Hydro energy model summary*

Hydro energy was the prime source of renewable energy in FY 2000, mainly from Snowy Hydro but also Tasmanian hydro. Government money would have been used to help construct Snowy Hydro but these have not been considered as subsidies in this thesis, given the time-line used. In FY 2013 the level of output exceeded the FY 2001 level for the first time but with little new hydro generation capacity being added this is more likely to be reflection of water being used to optimise LGHC revenue. The cost of emission reductions rises considerably to over AU$90/t

CO_2e over the 20 year period for reasons mentioned at the start of this section (Table 6.10). Further information on how output figures were determined is contained in Appendix A.3.

Table 6-10 Hydro generation output, subsidy costs and GHG emission reductions

FY	Output (GWh pa)	Total GHG emissn redns (thous t CO_2e)	Subs. related output (GWh pa)	Subsidy rel'd emissn redns (thous t CO_2e)	Subsidies, grants (AU$thous)	GHG redn subsidy cost (AU$/t CO_2e)	Amortized cost (AU$/t CO_2e)
2001	16,680	12,010	1,080	780	$38,900	$50	$50
2002	16,260	11,700	1,130	810	$40,650	$50	$50
2003	16,270	11,760	1,900	1,380	$70,420	$51	$51
2004	16,270	11,820	1,620	1,180	$61,440	$52	$52
2005	16,270	11,590	1,620	1,150	$55,040	$48	$48
2006	16,270	11,710	1,120	810	$26,900	$33	$33
2007	14,790	10,130	850	580	$21,980	$38	$38
2008	12,430	8,500	490	340	$24,130	$72	$72
2009	11,840	8,100	510	350	$26,630	$76	$76
2010	13,320	8,820	1,430	940	$57,040	$60	$60
2011	16,280	10,540	1,800	1,160	$68,300	$59	$59
2012	14,800	9,750	2,050	1,350	$77,790	$58	$58
2013	18,060	11,640	3,280	2,110	$111,470	$53	$53
2014	18,360	11,860	3,080	1,990	$92,330	$46	$46
2015	17,770	11,470	2,110	1,360	$84,250	$62	$62
2016	17,770	11,500	2,150	1,390	$128,810	$93	$93
2017	17,770	11,630	2,150	1,410	$128,942	$92	$92
2018	17,780	11,650	2,150	1,410	$129,070	$92	$92
2019	17,780	11,680	2,150	1,410	$129,210	$91	$91
2020	17,780	11,700	2,160	1,420	$129,340	$91	$91
Total	324,540	219,540	34,810	23,320	$1,502,640		

Note: non-single figures, except subsidy unit costs, rounded to nearest 10.

Source: IRENA (2015), AEMO Annual Statements of Opportunities, Energy Supply Association of Australia annual reports, Research paper to Australian Parliament 2001, Clean Energy Regulator (2015), Australian Government, Department of Industry and Science (2015a), AEMO (2015b).

6.2.4 *Bagasse energy model summary*

Bagasse cogeneration output is a reflection of a wider range of factors than other types of renewable energy because it is a secondary activity to the primary activity of sugar cane refining, resulting in greater financial viability compared with other types of renewable energy. Output each year reflects whether or not it was a good year for sugar production. Bagasse is not commonly stored, mainly because it is needed in the cogeneration process that produces electricity and steam, essential to the sugar refinery process. The bagasse that *is* stored provides the larger mills of Racecourse and Pioneer with opportunities to produce excess electricity for export to the grid at times of high pool prices.

Subsidy-related output averages 50% of total output growth because capacity that existed in the base year has been better utilised and because the marginal cost associated with increasing levels of available bagasse means it will be used to fire boilers rather than transported elsewhere. Industry consolidation is a further efficiency factor. The Mackay Sugar expansion is the only grant-related new capacity that has occurred since the RET scheme commenced. Further information on how output figures were determined is contained in Appendix A.3.

Volatility in output, reflecting good and bad sugar cane seasons, has resulted in per unit subsidy costs being more volatile than with other types of renewable energy. Emission reduction unit costs increase sharply in FY 2008 and FY 2015 for reasons mentioned at the start of this section (Table 6.11).

Table 6-11 Bagasse generation output, subsidy costs and GHG emission reductions

	Output	Total GHG emissn redns	Subs. related output	Subsidy rel'd emissn Redns	Subsidies, grants	GHG redn subsidy cost	Amortized cost
FY	(GWh pa)	(thous t CO_2e)	(GWh pa)	(thous t CO_2e)	(AU$thous)	(AU$/t CO_2e)	(AU$/t CO_2e)
2001	215	129	36	21	$1,284	$60	$60
2002	292	175	204	122	$7,330	$60	$60
2003	767	465	279	169	$10,306	$61	$61
2004	737	452	328	201	$12,450	$62	$62
2005	614	359	405	237	$13,773	$58	$58
2006	645	386	436	261	$10,464	$40	$40
2007	645	342	434	230	$11,290	$49	$49
2008	874	460	561	295	$27,473	$93	$93
2009	1,024	540	511	270	$26,552	$98	$98
2010	1,022	495	609	295	$24,376	$83	$83
2011	1,025	466	612	279	$23,271	$84	$84
2012	1,654	790	741	354	$28,172	$80	$80
2013	1,598	717	685	307	$32,275	$105	$79
2014	1,671	756	758	343	$22,752	$66	$69
2015	1,676	755	763	344	$30,512	$89	$91
2016	1,680	764	767	349	$46,030	$132	$134
2017	1,685	790	772	362	$46,293	$128	$130
2018	1,689	796	776	366	$46,556	$127	$130
2019	1,693	802	780	369	$46,818	$127	$129
2020	1,698	807	785	373	$47,081	$126	$128
Total	22,903	11,246	11,241	5,546	$515,057		

Note: non-single figures, except subsidy unit costs, rounded to nearest 10.

Source: IRENA (2015), AEMO Annual Statements of Opportunities, Energy Supply Association of Australia annual reports, Research paper to Australian Parliament 2001, Clean Energy Regulator (2015), Australian Government, Department of Industry and Science (2015a), AEMO (2015b).

6.2.5 *Biomass energy model summary*

Biomass covers a wide range of fuel sources including land-fill gas, wood and agricultural waste, and black liquor, with subsidies arising only from the creation of LGCs. Like bagasse the fuel is a by-product of another process and is comparatively inexpensive. The upsurge in output from FY 2005 was examined by noting LGC numbers from the REC Registry, showing an increase in black liquor and land-fill gas output, but not from any one development. As with bagasse, amortised emission reduction costs rise towards the end of the 20 year period (Table 6.12).

Table 6-12 Biomass generation output, subsidy costs and GHG emission reductions

	Output	Total GHG emissn redns	Subs. related output	Subsidy rel'd emissn redns	Subsidies, grants	GHG redn subsidy cost	Amortized cost
FY	(GWh pa)	(thous t CO_2e)	(GWh pa)	(thous t CO_2e)	(AU$thous)	(AU$/t CO_2e)	(AU$/t CO_2e)
2001	320	190	160	90	$5,630	$60	$60
2002	670	400	270	160	$9,680	$60	$60
2003	830	500	430	260	$15,800	$61	$61
2004	1,060	650	660	400	$25,000	$62	$62
2005	3,240	1,890	790	460	$26,760	$58	$58
2006	3,270	1,960	770	460	$18,430	$40	$40
2007	3,320	1,760	820	430	$21,220	$49	$49
2008	3,740	1,970	1,240	650	$60,610	$93	$93
2009	1,760	930	1,200	640	$62,560	$98	$98
2010	1,760	850	1,160	560	$46,480	$83	$83
2011	1,080	490	1,180	540	$44,730	$84	$84
2012	1,420	680	1,220	580	$46,320	$80	$80
2013	1,550	700	1,350	610	$45,900	$76	$76
2014	1,880	850	1,280	580	$38,310	$66	$66
2015	1,970	890	1,370	620	$54,830	$89	$89
2016	2,070	940	1,470	670	$88,160	$132	$132
2017	2,170	1,020	1,570	740	$94,370	$128	$128
2018	2,280	1,080	1,680	790	$100,890	$127	$127
2019	2,400	1,130	1,800	850	$107,740	$127	$127
2020	2,520	1,200	1,920	910	$114,920	$126	$126
Total	39,280	20,070	22,310	11,000	$1,028,350	$1,699	

Note: non-single figures, except subsidy unit costs, rounded to nearest 10.

Source: IRENA (2015), AEMO Annual Statements of Opportunities, Energy Supply Association of Australia annual reports, Research paper to Australian Parliament 2001, Clean Energy Regulator (2015), Australian Government, Department of Industry and Science (2015a), AEMO (2015b).

6.2.6 *Total large-scale renewable energy model summary*

When all forms of large-scale renewable energy are brought together (Table 6.13), the output level in FY 2020 is expected to exhibit an increase of 28,250 GWh (45,730 less 17,490), or 260% increase, over the FY 2000 base level. Compared with individual renewable energy types, there is a more stable trend in unit emission reduction costs, gradually rising to AU$47/t CO_2e in 2014 and then to AU$80/t CO_2e in FY 2020. The higher price in later years is a result of the increase in LGC prices in 2015 and lower levels of emission reductions caused by the NEM CIF continuing to decline. It is possible that LGC prices may increase above the AU$60/LGC used if it appears 33,000 MWh renewable energy target may not be met. However LGC prices are unlikely to reach the cap of AU$92.86/MWh as this would result in market speculation of very high levels of new renewable energy projects resulting in downward LGC market repricing.

Wind energy subsidy costs are the lowest, followed by hydro and solar energy. Bagasse cogeneration and biomass generation have higher remission reduction unit costs because they create emissions in the burning process of generating output. It should be remembered that these comments only relate to subsidised renewable energy so that hydro energy, although the largest source of renewable energy at present, provides the lowest level of subsidised renewable energy. Forecasts suggest that wind energy output will overtake hydro energy generation as the largest renewable energy source in several years' time.

Table 6-13 Total large-scale renewable generation output, subsidy costs and GHG emission reductions

	Output	Total GHG emissn redns	Subs. related output	Subsidy rel'd emissn redns	Subsidies, grants	GHG redn subsidy cost	Amortized cost
FY	(GWh pa)	(thous t CO_2e)	(GWh pa)	(thous t CO_2e)	(AU$thous)	(AU$/t CO_2e)	(AU$/t CO_2e)
2001	17,490	12,540	1,500	1,110	$53,880	$49	$49
2002	17,630	12,600	1,940	1,420	$69,880	$49	$49
2003	18,590	13,370	3,280	2,440	$121,240	$50	$50
2004	18,870	13,630	3,340	2,490	$126,790	$51	$51
2005	21,100	14,690	3,710	2,690	$126,130	$47	$47
2006	21,960	15,660	4,010	3,130	$96,290	$31	$31
2007	21,530	14,590	4,770	3,590	$123,990	$35	$35
2008	20,780	14,140	5,950	4,490	$291,510	$65	$65
2009	18,030	12,520	5,580	4,200	$290,260	$69	$69
2010	21,100	14,320	8,170	5,950	$326,870	$55	$55
2011	24,540	16,170	9,380	6,640	$356,580	$54	$54
2012	24,070	16,160	9,970	7,220	$390,230	$54	$53
2013	29,250	19,190	13,010	9,160	$517,140	$56	$49
2014	32,780	21,790	15,510	11,230	$513,190	$46	$43
2015	35,350	23,830	17,670	13,030	$798,640	$61	$56

2016	37,310	25,400	19,620	14,600	$1,328,250	$91	$83
2017	39,300	27,300	21,550	16,360	$1,293,180	$79	$81
2018	41,590	29,080	23,800	18,120	$1,427,770	$79	$81
2019	43,660	30,720	25,820	19,740	$1,548,890	$78	$80
2020	45,730	32,370	27,840	21,370	$1,670,350	$78	$80
Total	550,670	380,080	226,410	168,980	$11,471,080		

Note: non-single figures, except subsidy unit costs, rounded to nearest 10.

Source: IRENA (2015), AEMO Annual Statements of Opportunities, Energy Supply Association of Australia annual reports, Research paper to Australian Parliament 2001, Clean Energy Regulator (2015), Australian Government, Department of Industry and Science (2015a), AEMO (2015b).

6.3 Total renewable energy model summary

Renewable energy outcomes from each of household PV and large-scale renewable energy from previous chapters are brought together in Table 6.14.

Table 6-14 Total renewable generation output, subsidy costs and GHG emission reductions

Financial Year	Output	Emission redns	Subsidy related output	Subsidy related emission redns	Grants and subsidies	Emission redn subsidy cost	Amortised subsidy cost
	(GWh pa)	(thous t CO_2e)	(GWh pa)	(thous t CO_2e)	(AU$thous)	(AU$/t CO_2e)	(AU$/t CO_2e)
2001	17,490	12,540	1,500	1,110	$53,880	$49	$49
2002	17,630	12,600	1,940	1,420	$69,880	$49	$49
2003	18,590	13,370	3,280	2,440	$121,240	$50	$50
2004	18,870	13,630	3,340	2,490	$126,790	$51	$51
2005	21,100	14,690	3,710	2,690	$126,130	$47	$47
2006	21,970	15,660	4,020	3,130	$97,020	$31	$31
2007	21,540	14,600	4,780	3,600	$125,430	$35	$34
2008	20,820	14,170	5,990	4,530	$301,830	$67	$65
2009	18,140	12,620	5,690	4,300	$350,560	$82	$69
2010	21,510	14,670	8,570	6,300	$1,035,340	$164	$64
2011	25,710	17,180	10,550	7,660	$1,449,920	$189	$70
2012	26,390	18,180	12,290	9,240	$1,589,470	$172	$73
2013	32,670	22,170	16,430	12,140	$1,370,800	$113	$68
2014	37,040	25,500	19,770	14,940	$1,216,920	$81	$61
2015	40,340	28,170	22,660	17,370	$1,484,510	$85	$71
2016	43,020	30,370	25,320	19,560	$2,008,980	$103	$91
2017	45,680	32,860	27,940	21,920	$1,860,070	$85	$89
2018	48,570	35,150	30,770	24,190	$1,899,010	$78	$89
2019	51,140	37,240	33,300	26,250	$1,998,480	$76	$87
2020	53,640	39,250	35,750	28,250	$2,092,210	$74	$87
Total	601,840	424,610	277,580	213,510	$19,378,450		

Note: non-single figures, except subsidy unit costs, rounded to nearest 10.

Source: IRENA (2015), AEMO Annual Statements of Opportunities, Energy Supply Association of Australia annual reports, Research paper to Australian Parliament 2001, Clean Energy Regulator (2015), Australian Government, Department of Industry and Science (2015a), ARENA, Green Energy Markets (2014b), AEMO (2015b).

In FY 2014 subsidy-related renewable energy reduced GHG emissions by 14.9 m t CO_2e, being 3.7 m t CO_2e from household PV and 11.2 m t CO_2e from large-scale renewable energy (Table 6.14). By FY 2020 it is expected that the comparative contributions will be 6.9 m t CO_2e and 21.3 m t CO_2e respectively, totalling 28.2 m t CO_2e having similar growth rates. However emission reduction unit costs are very different, with household PV unit costs expected to decrease from AU$118/ t CO_2e in FY 2014 to AU$110/ t CO_2e in FY 2020. Large-scale renewable energy emission reduction costs are instead expected to increase from AU$46/ t CO_2e in 2014 to AU$80/ t CO_2e by 2020 (Figure 6.2). Household PV emission reduction costs are higher but decreasing whereas large-scale renewable emission reduction costs are lower but increasing. The diverse trends reflect the fact that high FITs gradually terminate while LGC prices have instead been increasing because of the overall LGC supply-demand balance (Figure 6.1). With the continuing expiry of high FITs household PV unit costs will fall below those of large-scale renewable energy in the early 2020s.

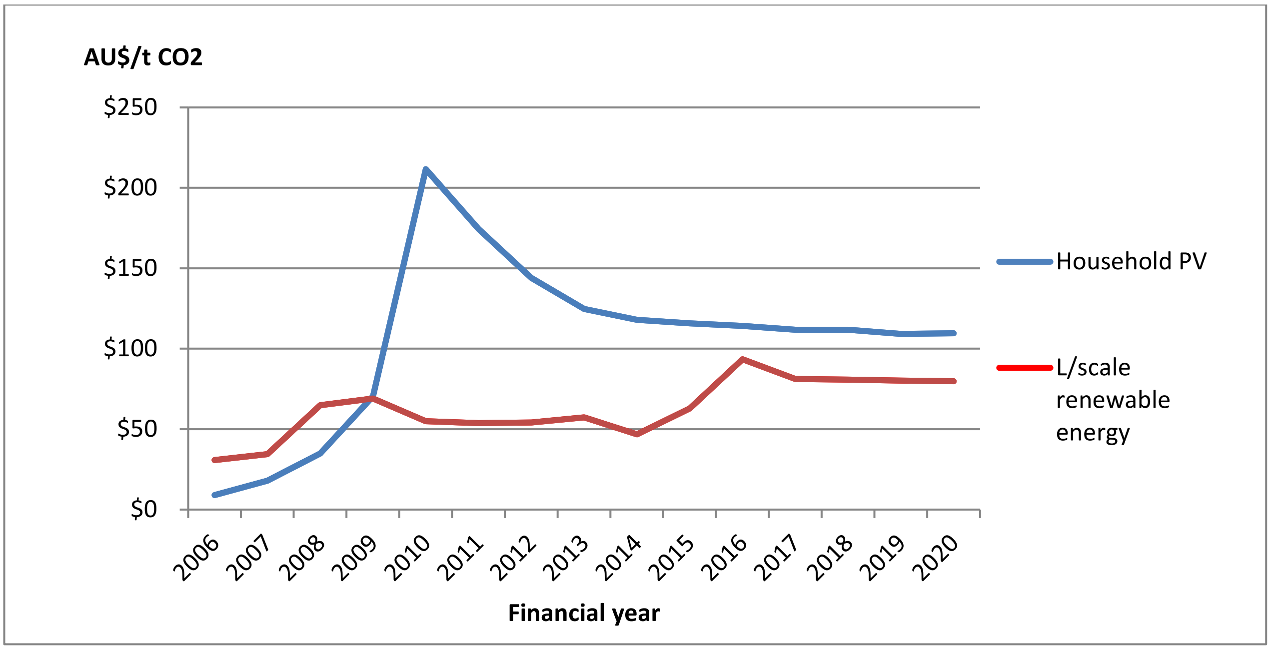

Figure 6-2 Amortised renewable energy unit subsidy costs

6.4 Non-renewable energy model results – carbon price

The focus of this thesis is on renewable energy and renewable-energy related issues that contribute to lowering GHG emissions. There is however also an emissions reduction benefit arising from the carbon price, being an additional cost contained in retail electricity prices, applying in FY 2013 and FY 2014. The outcome was a switch of generation from more carbon-intensive black and brown coal to gas-fired generation (Table 6.15). As discussed in Section 5.6.3 gas-fired generation has a lower carbon intensity factor than coal-fired generation, the difference being approximately 0.4 tonnes CO_2e per MWh. This generation type switch has been analysed over the two year carbon price period.

Table 6-15 Mix of generation type over carbon price period FY 2013 and FY 2014

Financial year	2012	2013	2014	2015
Brown coal (GWh pa)	55,070	47,900	46,080	46,000
%	22%	19%	19%	18%
Black coal (GWh pa)	116,650	112,060	105,770	105,000
%	47%	45%	43%	42%
Gas/oil (GWh pa)	52,360	56,600	59,410	59,000
%	21%	23%	24%	24%
Renewables (GWh pa)	25,800	33,200	37,040	40,340
%	10%	13%	15%	16%
Total (GWh pa)	249,880	249,760	248,295	250,340
growth		0%	-1%	1%

Note: GWh pa figures rounded to nearest 10.

Source: Australian Government, Department of Industry and Science, (2015a)

During the years of the carbon price, FY 2013 and FY 2014, gas-fired generation increased by 4,240 GWh and 2,810 GWh respectively, with the accumulative effect for FY 2014 being 7,040 GWh. Coal-fired generation decreased by more than this because of the growth in renewable energy. It could be concluded that most of the gas-fired generation increase was at the expense of the reduction in coal-fired generation because of the carbon price in FY 2013 and FY 2014. Millis (2016) advises that part of the upsurge in gas-fired generation was “due to the short-term availability of gas from coal-seam gas wells in advance of its requirement by the new facilities being built for LNG production and export”. The carbon price effect can therefore be considered only an upper bound. The upper bound of the carbon price effect for FY 2013 is reduced generation emissions of 1.7 m tonnes of CO_2e (4,238,000 MWh times 0.4) and for FY 2014 2.8 m tonnes (7,043,000 times 0.4), a combined 4.5 m tonnes of CO_2e. No account is taken of events after these two years when some sort of bounce back in coal-fired generation could have been expected but this has not happened suggesting that some of the impact was carried forward. Hence the two years of benefits could be considered optimistic, when noting the LNG effect, as well as being conservative when considering the possible ongoing benefits.

The outcome is that the carbon price has impacted both consumers and producers quite differently. Firstly it represents a form of subsidy paid by electricity consumers in their retail electricity prices, supporting household PV viability and encouraging electricity conservation, and secondly it represents a penalty paid by non-renewable electricity generators, albeit being a lower cost penalty for gas-fired generators compared with coal-fired generation.

The major anticipated emissions benefit was expected to be the reduction in GHG emissions by large, non-generator emitters. However these emitters were, in general, businesses having little opportunity to reduce emissions with the result being largely a cost impost.

The subsidy cost of the carbon price was approximately AU$4.5 billion in each of FY 2013 and FY 2014, being a total cost of AU$9 billion, paid by large emitters, which, as discussed in Section 6.4, achieved little in the way of emission reductions, but did result in government revenue used to drive energy efficiency and compensate households for the resultant electricity price rise. The important emissions impact occurred through electricity generators passing this cost on to electricity consumers through higher pool prices. The extra pool price cost is estimated at AU$4.9 billion, being pool price premium of AU$17.97/MWh (AU$17.62/MWh in FY 2013 and AU$18.32/MWh in FY 2014) at 270,000 GWh (two years NEM output excluding exempt penalty payers). The reduction in emissions of, at the most 4.5 million tonnes of CO_2e, creating an emission reduction cost in excess of AU$1,000/t CO_2e could suggest that this was not a cost-efficient emission reduction outcome. However the fact that the source of generation was being targeted meant that emissions reduction was likely to be more successful than targeting end-users. End-user consumption penalties encourage energy conservation which is important but does not have nearly the impact that energy producer emission penalties achieve. In summary the carbon price on large-scale emitters provided a source of government revenue but only marginal emission reductions, whereas the carbon price on energy producers appears to have been successful in reducing carbon emissions but at a high cost. The important unknown is the extent to which the switch from coal-fired to gas-fired generation might have occurred at a lower carbon cost.

6.5 Demand-side impact on energy demand and GHG emissions

The modelling of how households have been involved in demand-side energy reductions is made difficult by the various influencing factors as mentioned in previous chapters. The ideal outcome would be to remove all non-price factors affecting demand reduction so that price elasticities of electricity demand could be realistically calculated. Although this is not possible the analysis is assisted by the fact that many demand-side initiatives stem initially from high retail electricity prices and the consequent desire to take some form of cost savings action the main difference being the time span over which benefits will accrue. More energy efficient appliances, installed PV, more efficient hot water systems and similar measures will be undertaken with the economic impact being that long-run price elesticities of demand will be lower than those in the short term

Two approaches have been adopted to analysing the relationship between real electricity price increases and reduced electricity demand. The first is noting that there appears to be an electricity price trigger above which households, rather than accept higher cost consequences, decided to take action to reduce their electricity costs. A view of annual real electricity price increases and levels of electricity consumption suggests that this occurred in FY 2010 when real electricity price increases, from a FY 2000 base year, first exceeded 10 percent pa (Table 6.16). Saddler (2014) came to a similar conclusion commenting in regard to his own modelling “The most interesting finding of this part of the modelling is the abrupt change in consumer responsiveness to higher prices after 2010” (Saddler, 2014, p 5).

Electricity demand was first adjusted by adding back reduced consumption caused by households with PV to give an estimate of total demand that is influenced only by electricity prices. Demand was then “normalised” by applying the 1.6 % pa long-term demand growth rate to FY 2000 energy demand (of 210,018 GWh) and noting the excess demand above this level. This provides a base year to assist in assessing how actual demand has changed over time compared with the long-term electricity demand growth, a large part of which, since FY 2008, can be attributed to energy conservation measures including the growth in household PV. The key point of Table 6.16 is the substantial decrease in normalised energy demand after FY 2011 coinciding with the increase in real retail electricity prices above the 10% trigger**.**

The relationship between demand-reduction and increased retail electricity prices was first regressed over the years FY 2010 to FY 2015 but the fit was not good due to the FY 2010 outlier. This could reflect the fact that growth in energy conservation was most apparent post FY 2010, which is not surprising because this was the year when household PV exhibited most growth. The regression analysis was then taken over the five year period FY 2011 to FY 2015, with the results suggesting a more meaningful relationship (Figure 6.2).

Table 6-16 Energy reduction and increases in real electricity prices

FY	Total electricity demand (GWh pa)	H/hold PV demand reduction (GWh pa)	Total elec. demand - PV adjusted (GWh pa)	Normalised elec. demand incr.	Retail tariff (AU$/MWh)	FY 2008 tariff constant real terms (AU$/MWh)	Real tariff price incr.	Incr. above 10% trigger
2008	243,220		243,220		180.00	181.00	0%	
2009	249,530		249,530		198.00	186.00	6%	0.0%
2010	252,280	230	252,510	-2%	218.00	192.00	14%	3.6%
2011	253,300	670	253,970	-1%	236.00	197.00	19%	0.9%
2012	249,880	1,330	251,210	2%	261.00	203.00	29%	1.9%
2013	249,760	1,950	251,710	3%	296.00	209.00	41%	3.1%
2014	248,300	2,440	250,730	6%	315.00	216.00	46%	3.6%
2015	250,340	2,850	253,190	7%	325.00	222.00	46%	3.6%
2016	256,020	3,260	259,270		323.00			
2017	259,680	3,650	263,330		334.00			
2018	262,570	3,990	266,550		343.00			
2019	265,140	4,280	269,420		353.00			
2020	267,640	4,520	272,160		364.00			

Note: Prices rounded to nearest $ and demand figures rounded to nearest 10.

Source: Australian Government, Department of Industry and Science (2015a), Forecasts from Frontier Economics (2015), BREE (2015) for total demand

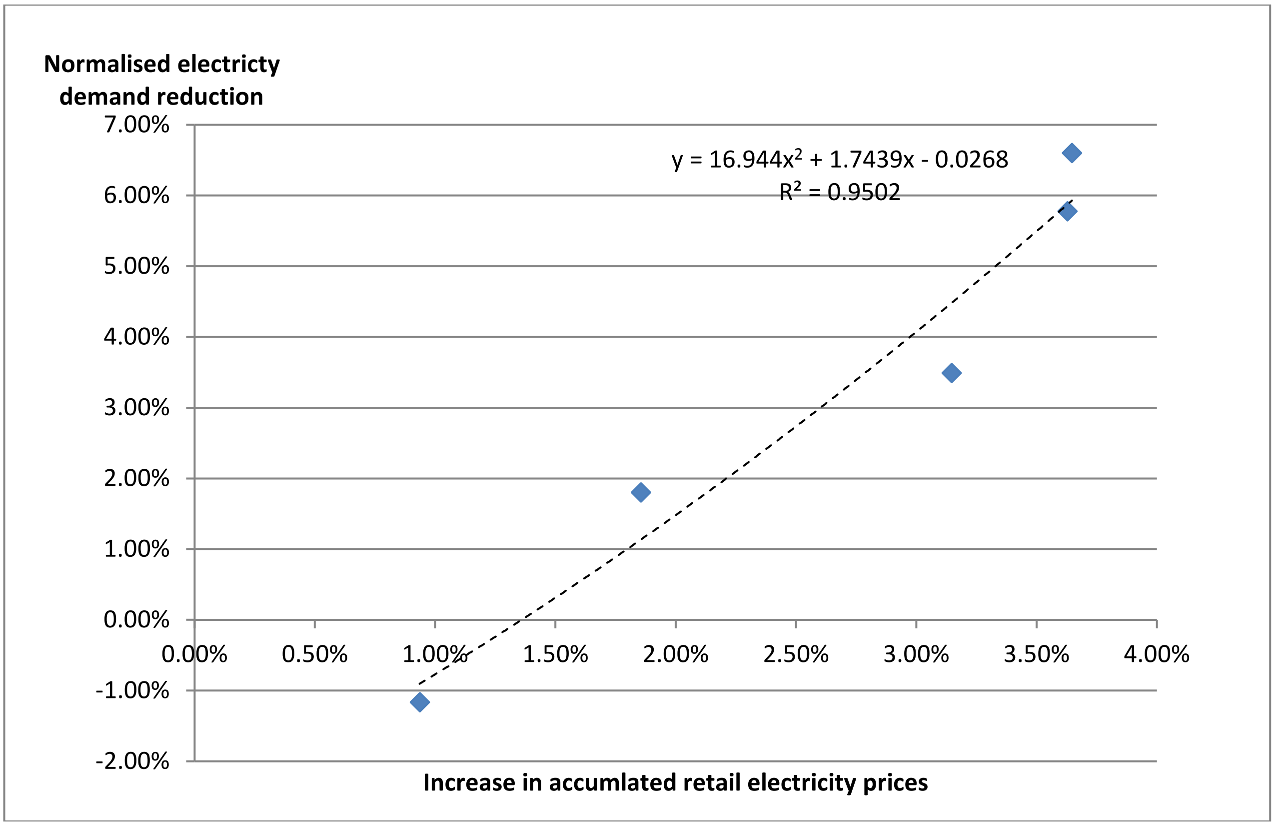

Figure 6-3 Relationship between real electricity price increases and reduced electricity consumption, FY 2011 to FY 2015

Given that there appears to be a close relationship between real electricity price increases and reduced electricity demand a second analysis was undertaken in an attempt to determine Australia's price elasticity of demand, the difference being that an incremental approach was adopted. Growth in electricity consumption is partly driven by population growth so demand was expressed on a per capita basis to remove this influence. It would have been ideal to concentrate only on household consumption but such information is not available; hence the analysis has the limitation of including commercial and industrial consumption but to the extent that they are also affected by population growth and increasing electricity prices the limitation is mitigated.

Over the period FY 2008 to FY 2015 real retail electricity prices increased each year and electricity demand per person declined each year (Table 6.17). For each year, price elasticities of demand were negative as expected and did not exceed unity, exhibiting a comparatively inelastic rather than elastic outcome, as could have been expected. There are aberrations on a year on year basis so the most realistic outcome is the result over the seven year period of a -0.4 price elasticity of demand. This is in line with DSM literature, as discussed in Section 5.9, with short-term price elasticity of demand in general ranging between -0.3 and -0.6. This analysis highlights the fact that subsidies resulting in higher retail electricity prices have resulted in reduced electricity demand and further contributed towards reducing GHG emissions.

Table 6-17 Estimate of Australian price elasticity of demand

FY	Real elec. price		Demand	Population	Demand per person		Price elas. of demand
	(AU$/MWh)	% inc	(GWh)	(million)	(MWh pp)	% decr.	
2008	181.00		243,220	20.0	12.2		
2009	192.00	6%	249,530	20.5	12.2	0%	0.0
2010	205.00	7%	252,280	21.0	12.0	1%	-0.2
2011	215.00	5%	253,300	21.5	11.8	2%	-0.4
2012	231.00	8%	249,880	22.7	11.0	7%	-0.9
2013	254.00	10%	249,760	23.1	10.8	2%	-0.2
2014	263.00	3%	248,300	23.7	10.5	3%	-0.9
2015	263.00	0%	253,150	24.2	10.5	0%	-3.8
2008 to 2015		46%				16%	-0.4

Note: Prices rounded to nearest $ and demand figures rounded to nearest 10.

6.6 Emission reduction costs in Australia and world-wide

GHG emission amortised reduction costs for household PV rose to a peak of over AU$200/ per t CO_2e in FY 2010 and have since been declining to an expected AU$110 per t CO_2e in FY 2020, mainly because of the phasing out of attractive FITs (Table 6.3). Large-scale renewable amortised energy emission reduction costs have instead steadily increased to an expected excess of AU$80/ per t CO2e by FY 2020 (Table 6.13). The Coalition government introduced a DAP scheme in 2015 to secure emission reductions through an auction process which to date has had an average cost of AU$14 per t CO_2e. Unlike other Australian schemes the cost is not applied directly to electricity consumers. These figures provide some perspective of the variation in types of emission reduction schemes in Australia, both in cost and the fact that in some cases electricity consumers pay and in others tax payers are liable.

If an ETS or CAT scheme is eventually introduced the outcome will instead be a cost to emitters, flowing through the economy, but at a market cost. Permits may be issued or auctioned which would have a price influence.

McKinsey & Company (2008) estimated that Australian household PV abatement costs for 2020 would be AU$65 per t CO_2e. A year later, on a world-wide basis they estimated, for 2020, PV abatement costs at EU$35 (AU$50) per t CO_2e (McKinsey & Company, 2009) followed by a reduction to EU$20 (AU$30) per t CO_2e a year later (McKinsey & Company, 2010). Large-scale solar abatement costs were nearly double these figures possibly due to the impact of subsidies. Ackerman and Bueno (2011) reviewed the work of McKinsey, producing abatement costs above those of McKinsey's postulating that this could be because McKinsey uses a broad "top-down" approach compared with their more detailed "bottom-up" approach. Ackerman and Bueno (2011) also raised the question of why negative cost abatement curves, determined by McKinsey & Company (2010) were not taken up. That is if there is no cost but instead a reward for taking action to reduce GHG emissions why is there not more of such action? In effect they were questioning part of McKinsey's analysis.

Bakhtyar et al (2014) analysed emission reduction costs on a world-wide basis utilising FITs in 13 countries or country regions. The results are not strictly comparable to those in this thesis as only FITs are considered, and not other subsidies such as REC subsidies as in Australia's case. Emissions were taken as average emissions per kWh of output rather than emissions at the margin thereby not reflecting the types of generation that would be replaced. In Australia's case a FIT of US80c/kWh was used, supposedly for Victoria, with this FIT applying also to all other forms of renewable energy which is not the case, reflecting the broad approach taken.

Kesicki (2011) analysed UK FITs for different renewable energy fuel types with wide ranges of outcomes. FITs were highest for PV at US$730 to US$1,073 per t CO_2e and potentially lowest for wind at US$20-878 per t CO_2e. With the wide variation the only conclusions that could be reached are that FITs were lowest for wind and likely to be very high for PV, similar to the results in this thesis.

Chapter 7 Sensitivity analyses

Summary

This chapter discusses how changes in subsidy components, and other model variables such as PV prices and levels of retail tariffs, alter the uptake of small and large-scale renewable energy and hence the level of GHG emissions. In effect these changes in input variables are sensitivity analyses but in some cases the changes are to variables which policy-makers have some control over, such as FIT prices and grants, and hence become scenario analyses. The period covered is initially from FY 2000 to FY 2015 and then extended to FY 2000 to FY 2020 encompassing forecasts, which are likely to be of more interest to policy-makers. Household PV is first examined in the context of the relationship between payback periods and actual uptake noting that if subsidies had been lower such that payback periods were never less than five years, savings of between AU$1 and AU$2 billion would have occurred with minimal uptake difference. Without any FITs or STCs almost 50% uptake of actual uptake would still have been likely. The impact on retail prices of no subsidies is also shown.

Large-scale renewable energy model results suggest that without subsidies little renewable energy growth would have occurred. Looking forward if LGC prices remain at their current AU$60/LGC to AU$70/LGC level, or increase further, then growth in large-scale renewable energy projects, particularly wind generation, will ensure the 20 % target will be easily achieved, with payback periods falling to between seven and eight years. The total cost of subsidies to electricity consumers is estimated to be AU$8.0 billion between FY 2000 and FY 2014, increasing to an expected AU$19.4 billion for the FY 2000 to FY 2020 period (Table 6.14).

Analysis background

The model has been created with linkages between key variables to enable sensitivity analyses to be undertaken. It is important to recognise that not all input variables are independent of each other with some inputs being common to all types of renewable energy projects, such as changes in electricity prices. There are also market-related relationships such as that between LGC prices and wholesale electricity prices. It is the combination of the two that provides large-scale renewable energy projects with the necessary revenue for viability. If the electricity price is comparatively low the LGC price will increase to ensure sufficient projects are viable to generate the number of LGCs necessary to enable retailers to meet their liability obligations (and hence the overall LGC target). If this is not the case retailers will be required to pay the LGC shortfall penalty, of AU$92.86/LGC tax adjusted. To avoid doing this retailers will increase the price they are willing to pay for LGCs until they are eventually high enough to enable additional renewable energy projects to become viable thereby and generating sufficient extra LGCs. In effect a typical economic supply and demand relationship will be operating. Although this is a self-fulfilling mechanism there is a timing issue in that renewable energy projects cannot instantaneously come into effect resulting in a time delay giving rise to LGC prices rising to higher than equilibrium levels until sufficient project-generated LGCs become available.

The main focus of the sensitivity analyses has been on the impact of how changes in subsidies might affect household and large-scale renewable energy output, changes in emission reduction levels and changes in retail electricity prices.

7.1 Sensitivity of household PV uptake to reduced subsidy levels

As discussed in Section 5.6.2 FITs and the REC multiplier were higher than necessary to achieve the resultant levels of PV uptake. Policy makers had not anticipated the coincidental drop in the cost of solar panels, mostly from China, by over 50%, and the strong interest by households in seeking to take some control of their electricity costs. If the level of FITs had been less attractive and the STC multiplier lower, such that payback periods were never less than five years, the uptake would have been only marginally less but the level of subsidies would have been reduced by between AU$1.0 billion and AU$2.0 billion. This conclusion was achieved by first noting the maximum level of subsidy reduction that could have been achieved and then noting what realistically could have been achieved.

In the years when payback periods were less than five years, being FY 2011 to FY 2015, subsidy savings of AU$2 billion potentially could have been achieved (Table 7.1).

Table 7-1 Household PV subsidy savings if no annual payback period is less than five years

FY	Annual p/back	Net cap. cost	Annual benefit	Annual benefit at 5 yr P/Back	Difference	Five year difference	Total number of installations	Total savings
	(years)	(AU$)	(AU$)	(AU$)	(AU$)	(AU$)		(AU$m)
2011	3.3	$3,900	$1,170	$780	$390	$1,940	350,900	$680
2012	2.8	$3,520	$1,240	$700	$540	$2,690	331,200	$890
2013	3.9	$4,370	$1,110	$870	$240	$1,200	198,900	$240
2014	4.5	$4,850	$1,080	$970	$110	$520	173,100	$90
2015	4.8	$4,810	$990	$960	$30	$150	164,400	$30
Total								$1,930

Note: Cost and benefit figures have been rounded to nearest AU10 m.

Source: Sensitivity analysis of model output (Figure 6.1)

Table 7-2 Practical changes in subsidy levels that could achieve substantial savings

FY Year	FIT benefit	Act. FIT	Lower FIT	FIT diff.	FIT cost redn	STC multiple	Reduced STC multiple	Capital cost diff.	No. of instal'ns	STC savings	Revised P/back
	(AU$m)	(AU$/MWh)	(AU$/MWh)	(AU$/MWh)	(AU$M)			(AU$)		(AU$m)	(years)
2011	$790	57.96	30.00	27.96	$380	4	4				5.0
2012	$740	43.09	25.00	18.09	$310	3	2	$720	331,200	$240	4.5
2013	$410	15.23	15.23	0.00	0.00	1.5	1	$410	198,900	$80	4.3
2014	$260	5.10	5.10	0.00	0.00	1	1				4.4
2015	$190	2.53	2.53	0.00	0.00	1	1				4.8
Total					$690					$320	

Note: Cost and benefit figures have been rounded to nearest AU10 m.

Source: Table 7.1

In reality the AU$2 billion savings (Table 7.2) would not have been possible for a number of reasons including difficulties spreading savings effectively between years and unrealistic implications for some FITs. The approach taken has been to firstly reduce FITs in the highest FIT year of FY 2011 to a state average of AU30c/kWh being equivalent to a 5 year payback period, producing AU$380 m savings over the first five year for households that installed PV in FY 2011. Savings would in reality be greater than this as most FITs had terms of more than five years. The FIT for FY 2012 was reduced to an average AU25c/kWh being marginally greater than average tariff levels which would remain attractive. No further FIT reductions were considered as the average FIT for new installations post FY 2012 had already been substantially reduced (Table 7.2). These reduced FITs would generate subsidy savings of AU$690 m.

As mentioned in Section 5.6.2 large STC subsidies also occurred during these years, particularly in the form of STC multipliers. This was recognised at the time with the multiplier deadline brought forward a year to the end of 2013. If the multiplier had been reduced from 3 to 2 in FY 2012 and to unity in FY 2013 there would have been additional subsidy savings of AU$320 m. These savings are recognised in higher capital costs paid by households because STCs are used by installers to discount capital costs. The combined effect of both lower FITs and reduced STC multipliers is to produce AU$1 billion in subsidy savings with payback periods continuing to remain below 5 years, being still attractive (Table 7.2).

The substantial household PV uptake had become obvious by early 2010 providing time to react for FY 2011. Adjustment to STC multipliers would have been easier to achieve as they are part of a national scheme whereas FIT are state-based but might have been more successful if they had been a nationwide scheme. This would have allowed a speedier reaction to linking FITs to market prices, as occurred in Germany, for example (GAU, 2000).

In the extreme example of no FITs being provided and no STCs being available there is likely to still be some uptake of household PV over the period FY 2000 to FY 2020 because PV panel costs have fallen, retailers are likely to be willing to make some payment for electricity generated and there will continue to be material savings from solar output offsetting domestic consumption. Looking ahead the possibility of increasingly more attractive battery storage costs occurring when attractive FITs expire is likely to provide further PV support.

The extreme example was modelled of setting FITs and STCs to zero, removing the carbon price over the two years FY 2013 and FY 2014 and also removing the large-scale renewable energy subsidy reflected in LGCs. The effect on retail electricity prices is shown in Table 7.3.

Table 7-3 Retail electricity prices with and without subsidy components

FY	Actual and forecast retail prices (AU$/MWh)	Subsidy component (AU$/MWh)	Annual prices without subsidies (AU$/MWh)	Price decrease
2001	132.00	0.04	132.00	0.0%
2002	142.00	0.12	142.00	0.1%
2003	151.00	0.27	151.00	0.2%
2004	159.00	0.45	158.00	0.3%
2005	163.00	0.55	163.00	0.3%
2006	168.00	0.51	167.00	0.3%
2007	174.00	0.71	173.00	0.4%
2008	181.00	2.00	179.00	0.9%
2009	198.00	2.00	196.00	1.0%
2010	218.00	5.00	213.00	2.1%
2011	236.00	11.00	224.00	4.7%
2012	261.00	14.00	248.00	5.2%
2013	296.00	48.00	248.00	16.1%
2014	315.00	39.00	276.00	12.4%
2015	325.00	11.00	315.00	3.2%
2016	323.00	13.00	310.00	4.1%
2017	334.00	14.00	319.00	4.2%
2018	343.00	16.00	328.00	4.5%
2019	353.00	17.00	335.00	4.9%
2020	364.00	19.00	344.00	5.4%

Note: Prices above AU$1 have been rounded to nearest dollar

Source: AEMC (2013), Australian Government, Department of Industry, Innovation and Science. (2015), Forecasts from Frontier Economics (2015), AER (2015)

The price decreases reflect subsidy contributions paid by consumers in each financial year. In the extreme year of FY 2013 the subsidy impact, from all forms of subsidies, was to increase retail electricity prices by 16 percent higher. The impact going forward, being mainly due to the cost of LGCs, is an ongoing 5 percent increase to retail electricity prices.

The expected household PV uptake at these no-subsidy price levels results in payback periods increasing to at least six years in every year (Table 7.4). The modelled relationship (Figure 6.1) was used to convert these higher payback periods to lower levels of uptake of household PV in each year. For the 20 year period to FY 2020 capacity is predicted to reduce from 6,190 MW to 4,050 MW and output from 51,170 GWh to 28,300 GWh. The overall decrease is less than 50 percent reflecting the likelihood that PV uptake is less influenced by subsidies from FY 2015 to FY 2020. That is even though uptake from FY 2015 is expected to decline by nearly 50 percent this partly reflects the increasing level of household PV saturation which is unlikely to be greatly impacted by changing economics. In effect without any subsidies there would still have been a substantial uptake of household PV despite capital costs, without subsidies, being higher on average by AU$1,000 per PV unit. Benefits would not have fallen substantially because there would still have been savings from reduced electricity consumption as well as export credits, in the order of AU8c/kWh that would still be provided by retailers.

Table 7-4 Household PV output with and without subsidies

	Payback with subsidies	PV model uptake	Payback without subsidies	PV model uptake, no subsidies	PV uptake decrease	Actual and forecast uptake	Uptake, no subsidies	PV output with subs.	PV output no subs.
FY	(yrs)	(MW)	(yrs)	(MW)	(MW)	(MW)	(MW)	(GWh)	(GWh)
2006	47.4	10	49.8	5	5	2	0	2	0
2007	43.5	20	45.0	10	10	6	0	10	0
2008	32.5	30	35.3	15	15	20	8	40	10
2009	16.1	160	31.2	20	140	60	0	110	10
2010	5.4	570	26.4	50	520	230	0	400	10
2011	3.3	750	15.4	180	580	600	25	1,170	40
2012	2.8	800	9.6	340	460	900	440	2,320	610
2013	3.9	730	7.4	450	280	860	580	3,420	1,350
2014	4.5	650	6.5	530	120	660	540	4,260	2,040
2015	4.8	610	6.5	530	80	570	490	4,990	2,660
2016	5.1	600	6.6	530	70	560	490	5,700	3,290
2017	5.5	530	6.7	470	60	530	470	6,380	3,890
2018	5.6	460	6.9	400	60	460	400	6,970	4,400
2019	5.8	400	7.1	330	70	400	330	7,480	4,820
2020	5.9	330	7.3	280	50	330	280	7,910	5,180
Total		6,650		4,130	38%	6,190	4,050	51,170	28,300

Total to 2014	3,720	1,600	57%	3,340	1600	11,730	4,060

Note: Non-single figure capacity and output figures have been rounded to nearest 10

Source: Sensitivity analysis of model output (Figure 6.1)

The no-subsidy outcome is for emission reductions to fall to nearly half of those under the subsidy scenario with subsidy savings of nearly AU$8 billion (Table 7.5).

Table 7-5 Household PV output emissions with and without subsidies

	Expected outcome with subsidies			Expected outcome - no subsidies			
FY	Output	Emission reductions	Subsidy costs	Output redn (%)	Output	Emission reductions	Subsidy costs
	(GWh)	(th. t CO2)	(AU$000)		(GWh)	(th. t CO2)	(AU$000)
2001	0	0	$0	0%	0	0	$0
2002	0	0	$0	0%	0	0	$0
2003	0	0	$0	0%	0	0	$0
2004	0	0	$0	0%	0	0	$0
2005	0	0	$0	0%	0	0	$0
2006	2	2	$1	74%	0	1	$0
2007	10	10	$1	91%	0	1	$0
2008	40	40	$10	97%	10	1	$0
2009	110	100	$60	96%	10	4	$0
2010	400	350	$710	74%	10	90	$0
2011	1,170	1,020	$1,090	61%	40	400	$0
2012	2,320	2,020	$1,200	52%	610	970	$0
2013	3,420	2,970	$850	47%	1,340	1,590	$0
2014	4,260	3,710	$700	42%	2,040	2,140	$0
2015	4,990	4,340	$690	39%	2,660	2,650	$0
2016	5,700	4,960	$680	37%	3,290	3,130	$0
2017	6,380	5,550	$570	36%	3,890	3,580	$0
2018	6,970	6,070	$470	35%	4,400	3,970	$0
2019	7,480	6,510	$450	45%	4,820	3,600	$0
2020	7,910	6,880	$420	65%	5,180	2,380	$0
Total	51,170	44,530	$7,910	38%	28,300	24,500	$0

Note: Non-single figure numbers have been rounded to nearest 10.

Source: Table 7.4 and Table 6.3

7.2 Sensitivity of large-scale renewable energy output to reduced subsidy levels

Two types of subsidies have had the greatest impact in stimulating large-scale renewable energy projects in Australia, being one-off grants and ongoing LGCs. Low cost finance, provided by the

Clean Energy Finance Corporation (CEFC) represents a further subsidy but this aspect has not been included in the analysis as the impact is not as great as the other two types of subsidies.

An analysis has been undertaken of the likely outcome in Australia if no grants, from states or the Commonwealth, had been available and the LRET scheme, providing LGCs, had not existed. Variations to this scenario are possible but have not been examined because of the complexity of assumptions and because the no-subsidy scenario is the extreme case which has most value. Subsidy savings are compared with the higher level of emissions that would have occurred to assess the impact on renewable energy and emission targets not being reached.

It was first noted that some large-scale renewable energy projects have occurred since the RET scheme was introduced *without* the assistance of subsidies. This was observed by noting the extent to which there has been growth in renewable output in excess of the growth in the creation of LGCs.

In the case of wind energy there was small non-subsidised growth prior to 2001 but little non-subsidised growth since then. With large-scale solar it was observed that at least since the mid 1990s there has been increasing growth in non-subsidised solar, exhibited in output growth exceeding the growth in LGCs. It has been assumed that this growth will continue and is the main component of non-subsidised renewable energy growth. Hydro energy output fell by over 4,000,000 GWh between 2002 and 2009, reflecting the drought of 2008 and 2009, falling below the hydro energy base line but still producing LGCs (which was not able to be explained in communications between the author and the CER in March 2016). It has been assumed that output fluctuations will continue but not as a result of increased capacity expansion. With bagasse it was noted that output has continued to exceed expectations when comparing net out output with LGC creation in the period since FY 2012 by an average 400 GWh pa. Biomass output exceeded LGC determined output between FY 2011 and FY 2013 by 400 GWh pa but since then there has been a close alignment with LGC driven output. Hence no non-subsidised output has been assumed in future forecasts. In summary there has been some solar growth and bagasse growth that has arisen without subsidies. The analysis now focuses on the extent to which subsidised output would have continued without subsidies.

Renewable energy projects fall into two categories, being large projects receiving state or Commonwealth grants and smaller projects where viability is dependent on the number and price of LGCs created. As in the case of most renewable projects the receipt of contracted forward prices is critical to the project's ongoing viability. This is highlighted in the financial difficulties experienced by the two 30 MW northern NSW bagasse cogeneration projects, Condong and

Broadwater which began operation in 2008, and the more recent experience of Hydro Pacific's wind turbine portfolio. In both cases the projects went "merchant" on LGC revenue, that is they were fully exposed to varying wholesale LGC prices which had remained depressed until early 2015 resulting in the two bagasse projects being sold under duress in 2013 and Hydro Pacific reporting a AU$780 million financial loss in early 2015. This position however will have improved substantially with the dramatic increase in LGC prices since mid 2015. These examples show the importance of securing fixed forward prices, creating revenue certainty and greater interest by financiers in financing such projects. Falls in subsidy levels, such as those now being examined, would then not affect viability over the contract period. In this analysis it is assumed that such contract terms are not long enough to overcome the viability consequences of no subsidies.

Viewing model results of large-scale renewable project viability suggests that the only projects that could in future be viable without subsidies, are those that are an adjunct to another activity such as bagasse cogeneration and biomass generation. Solar is often referred to as being close to viability without subsidies but in an Australian context this is more relevant to household PV. For large-scale solar the value of LGCs at the current (November 2015) price of AU$60/LGC, creates an output purchase price in the order of AU$120 to AU$130/MWh. Excluding the LGC price produces an output price of AU$60/MWh to AU$70/MWh which is not adequate for viability. Wind energy is in a similar position. It is difficult to analyse biomass because it covers a wide range of fuel types but rapid growth, since the availability of LGCs, suggests that most of the output is subsidy driven.

There could be some output increases, not subsidy related, arising from more intensive use of capacity that existed in 2000. The reason for this is that there are no fixed costs related to extra output from existing plant so that such output could occur despite the fact that there are no subsidies for this purpose. To evaluate this impact the model was used to view capacity and output in each year from FY 2000 to FY 2020 for each type of renewable energy. Not surprisingly subsidised solar and wind output were found to increase only in line with additional capacity (as improved capacity utilisation is a reflection only of climatic conditions). Hydro energy output could have been used more efficiently but over the 20 year time period it was found that productivity varied considerably year by year, being a reflection of weather and hydrology patterns over time. Broadly over the 20 year period there was no real net hydro energy output change. Non-subsidy related renewable energy growth therefore focussed on non-subsidised solar, which continued to show growth from the 1990s, and bagasse cogeneration. The diverse nature of biomass products meant detailed analysis was not possible.

Output of non-subsidised solar was determined as growth since FY 2002 less the FY 2002 baseline output of 58 GWh pa. For bagasse the approach taken was to note the average number of hours per day cogeneration plants operated each year, being 6 hours per day in 2001 and deducting this figure from the average number of operating hours in each subsequent year. These figures excluded the 24/7 bagasse plants introduced during this (Pioneer, 70 MW in FY 2003, and Racecourse, 38 MW in FY 2012 and FY 2013) as their contributions distort productivity improvements. The outcome suggested that non-subsidised bagasse output was likely to gradually increase to a forecast 230 GWh improvement by FY 2020 (Table 7.6).

Total subsidies saved over the 20 year period would have been AU$11.5 billion and GHG emissions would have been 164.3 m t CO_2e higher, being 169.0 m t CO_2e (Table 6.13) less 4.7 m t CO_2e (Table 7.6). Renewable energy capacity would have increased only marginally (from non-subsidised solar) above the FY2001 level of 8,400 MW, 96% of which would have been hydro.

Table 7-6 Large-scale renewable energy output with and without subsidies

	Expected outcome with subsidies			Expected outcome - no subsidies		
FY	Subsidy related output	Subsidy related emission reductions	Subsidy costs	Output	Emission reductions	Subsidy costs
	(GWh)	(th. t CO2)	(AU$000)	(GWh)	(th. t CO2)	(AU$000)
2001	1,500	1,110	$50	0	0	$0
2002	1,940	1,420	$70	0	0	$0
2003	3,280	2,440	$120	0	0	$0
2004	3,340	2,490	$130	9	6	$0
2005	3,710	2,690	$130	20	10	$0
2006	4,010	3,130	$100	70	40	$0
2007	4,770	3,590	$120	80	50	$0
2008	5,950	4,490	$290	120	80	$0
2009	5,580	4,200	$290	130	80	$0
2010	8,170	5,950	$330	150	100	$0
2011	9,380	6,640	$360	460	300	$0
2012	9,970	7,220	$390	360	230	$0
2013	13,010	9,160	$520	490	310	$0
2014	15,510	11,230	$510	640	410	$0
2015	17,670	13,030	$800	670	430	$0
2016	19,620	14,600	$1,330	720	460	$0
2017	21,550	16,360	$1,290	830	530	$0
2018	23,800	18,120	$1,430	820	530	$0
2019	25,820	19,740	$1,550	880	560	$0
2020	27,840	21,370	$1,670	930	590	$0
Total	226,410	168,980	$11,470	7,370	4,720	$0

Note: Non-single figure numbers have been rounded to nearest 10.

Source: Table 6.12

Model payback periods were also used to determine the circumstances in which renewable projects could have been viable, without subsidies. The lowest payback periods, with subsidies, excluding those affected by substantial capital grants, is seven years occurring frequently between FY 2013 and FY 2020. If LGCs instead had a zero value the lowest payback periods become those for large-scale solar at 10 years in FY 2013 and FY 2014; for other years payback periods do not fall below 13 years. Based on the response to payback periods for household PV, comments in ASMC (2014) and the views of financiers[7], it is possible that some large-scale solar in FY 2013 and FY 2014 could have been viable without LGCs. In these years wholesale electricity prices, with a premium to reflect the profile of solar energy output, were higher than in any other years being the key viability factor. Under this scenario the only large-scale renewable energy projects that might have prevailed would have been 100 MW of solar in FY 2013 and 22 MW of solar in FY 2014, a total 120 MW, having output of 310 GWh pa and emission reductions of 199 thousand tonnes pa. This is about 13 % of subsidy-related emission reductions and although material is an upper limit of possible outcomes. It should be stressed that this conclusion reflects modelling outcomes, dependent on a range of assumptions, some of which, as mentioned, relate only to FY 2013 and FY 2014 and hence may not be seen as indicative of the future, being the view developers might take. Modelling results here, and elsewhere in this thesis, therefore need to be treated with caution.

The model was also used to understand outcomes with subsidies increasing rather than decreasing. With current grants and a continuation of recent AU$70/LGC prices, payback periods for wind and solar reduced from between 12 to 18 years prior to FY 2012, to approximately 10 years at present and reducing further to between seven and eight years over the next five years, providing support to the growth currently taking place. Hydro energy output was not considered to be sensitive to LGC prices as decision-making involves many other factors, including environmental and regulatory issues. Bagasse and biomass were also not considered as the economics are impacted by a range of factors, as mentioned earlier.

7.3 Sensitivity of total renewable energy output to reduced subsidy levels

In the extreme case of no subsidies for any type for renewable energy, there would still be growth in household PV but little growth in large-scale renewable energy projects (Section 7.1).

---

[7] The author met with various financiers, including banks, during his 10 year role exploring renewable energy project viability between 2002 and 2012.

For household PV with subsidies limited to payback periods of no less than five years the outcome was a comparatively small reduction in household PV uptake with potential AU$2 billion in subsidy savings, reducing to AU$1 billion when viewing changes that could have realistically occurred.

The analysis now brings together information from earlier sections to show outcomes for total renewable energy without subsidies (Table 7.7).

Table 7-7 Total renewable energy output with and without subsidies

	Expected outcome with subsidies			Expected outcome without subsidies		
FY	Subsidy related output	Subsidy related emission reductions	Subsidy costs	Output	Emission reductions	Subsidy costs
	(GWh)	(th. t CO2)	(AU $000)	(GWh)	(th. t CO2)	(AU$000)
2001	1,500	1,110	$50	0	0	$0
2002	1,940	1,420	$70	0	0	$0
2003	3,280	2,440	$120	0	0	$0
2004	3,340	2,490	$130	9	6	$0
2005	3,710	2,690	$130	20	10	$0
2006	4,020	3,130	$100	70	40	$0
2007	4,780	3,600	$130	80	50	$0
2008	5,990	4,530	$300	130	80	$0
2009	5,690	4,300	$350	140	80	$0
2010	8,570	6,300	$1,040	160	190	$0
2011	10,550	7,660	$1,450	510	700	$0
2012	12,290	9,240	$1,590	960	1190	$0
2013	16,430	12,140	$1,370	1,830	1,900	$0
2014	19,770	14,940	$1,220	2,680	2,550	$0
2015	22,660	17,370	$1,490	3,330	3,080	$0
2016	25,320	19,560	$2,010	4,010	3,600	$0
2017	27,940	21,920	$1,860	4,730	4,110	$0
2018	30,770	24,190	$1,900	5,230	4,500	$0
2019	33,300	26,250	$2,000	5,700	4,160	$0
2020	35,750	28,250	$2,090	6,100	2,980	$0
Total	277,580	213,510	$19,380	35,670	29,220	$0

Note: Non-single figure numbers have been rounded to nearest 10.

Source: Table 7.5 and Table 7.6

The effect on the level of total renewable energy output, if there were no subsidies, would be to reduce output over the period FY 2000 to FY 2020 by 241,910 GWh (that is 277,580 less 35,670) with almost all large-scale renewable output not eventuating but 50% of household PV still occurring. Although AU$19.4 billion of subsidies would be saved the total level of emission reductions would be substantially reduced (by 184.3 m t CO_2e, from 213.5 m t CO_2e to 29.2 m t CO_2e).

A further scenario is the situation if there were no household PV subsidies, just those for large-scale renewable energy. Large-scale renewable energy output is expected to total 45,730 GWh in FY 2020 being 17 % of total expected generation, so that the target of 20% of total energy from renewable sources would not be met (Table 6.13).

7.4 Effect on retail electricity prices without renewable energy subsidies

Electricity consumers have been increasingly subsidising the cost of renewable energy since FY 2001, with the carbon price in FY 2013 and FY 2014 having the most noticeable impact (Table 7.3). Subsidies peaked at AU$8.0 billion in FY 2013 and are forecast to average AU$3 billion pa to FY 2020 (Table 7.8).

Table 7-8 Cost of subsidies paid by electricity consumers

	Actual and forecast retail prices	Subsidy component	Annual prices without subsidies
FY	(AU$/MWh)	(AU$/MWh)	(AU$/MWh)
2001	132.00	0.04	132.00
2002	142.00	0.12	142.00
2003	151.00	0.27	151.00
2004	159.00	0.45	158.00
2005	163.00	0.55	163.00
2006	168.00	0.51	167.00
2007	174.00	0.71	173.00
2008	181.00	2.00	179.00
2009	198.00	2.00	196.00
2010	218.00	5.00	213.00
2011	236.00	11.00	224.00
2012	261.00	14.00	248.00
2013	296.00	48.00	248.00
2014	315.00	39.00	276.00
2015	325.00	11.00	315.00
2016	323.00	13.00	310.00
2017	334.00	14.00	319.00
2018	343.00	16.00	328.00
2019	353.00	17.00	335.00
2020	364.00	19.00	344.00
Total			

Note: Figures above AU$1 have been rounded to nearest dollar.

Source: ROAM Consulting (2012), Frontier Economics (2015) for forecasts, Parliament of Australia (2009) for EITE assumptions.

There are variations in retail electricity price forecasts, mainly relating to network charges, which contribute nearly 50% of total retail prices. Frontier Economics (2015) retail electricity price forecasts have been used which are higher than those of Green Energy Markets (2014) whose forecasts contain energy and network costs decreasing in real terms between FY 2015 and FY 2020, possibly being overly conservative.

The position can also be viewed in the case of no renewable energy subsidies at any time. For the period FY 2001 to FY 2015 the subsidy component would have totalled AU$133/MWh, reducing the FY 2015 retail electricity price from AU$325/MWh to AU$192/MWh, a reduction of 41%. Similarly for the 20 years to FY 2020 the retail electricity price would have been 59% lower, at AU$151/MWh (Table 7.8). The larger reduction in FY 2020 reflects the extra five years of subsidies, principally relating to LGCs, included in the retail price. This highlights the extent to which electricity consumers subsidise renewable energy.

This thesis has focused on subsidies stimulating renewable energy, being grants and electricity price subsidies. Although these are amounts actually received by renewable energy developers they are less than what they could have otherwise been. For example PV installers credit households with STCs at an estimated 20% discount to market prices. In addition retailers electricity prices contain regulated margins of approximately 17%, which is in effect a premium applied to STC and LGC retail components. Together these margins result in an average 18% premium applied to the subsidies received by renewable energy developers. This is a conservative calculation as it excludes the difference between the prices electricity retailers actually pay for STCs and LGCs and the prices negotiated with regulators, often being at the capped price. An 18% premium is equivalent to the total level of subsidy payments (Table 7.7) increasing from AU$19.4 billion to AU$22.9 billion, being the amount actually paid by electricity consumers. It could be argued that the difference of AU$3.5 billion is justified in reflecting the activities of installers in creating and on-selling STCs and electricity retailers in undertaking similar activities including taking on price risk[8]. For these reasons no adjustments have been made to other figures in this thesis.

Electricity consumers have also been paying a network cost premium for additional network capacity that may not have been necessary, as mentioned in Section 5.6.2. An evaluation of this network cost “premium” has been made by assessing the impact if network costs had increased at the same rate as other components of electricity prices. The outcome is that the largest “excess”

[8] These comments reflect the experiences of the author in undertaking price negotiations with the Queensland energy regulator.

network energy charges occurred post 2012 when network cost increases in excess of 20% pa were approved by regulators (Table 7.9). Although greater restraint in network costs increases has been signalled for the future the build-up of increases during the 2011 to 2013 period remain imbedded in the retail tariff structure. These "excess" network energy charges represent a further subsidy paid by electricity consumers to reduce GHG emissions, through the effect of reduced electricity consumption, as discussed in Section 6.5.

Table 7-9 Reduction in network costs if increases had been at same rate as other retail electricity cost components

	Actual and forecast retail prices	Network component	Retail prices exc. network	Increase in ret. prices exc. network	Network comp. at ret. price ex. network inc.	Retail prices at lower network comp.	Network cost savings
FY	(AU$/MWh)	(AU$/MWh)	(AU$/MWh)		(AU$/MWh)	(AU$/MWh)	(AU$m)
2001	132.00	64.00	68.00		64.00	132.00	0
2002	142.00	72.00	70.00	3%	66.00	136.00	910
2003	151.00	81.00	70.00	0%	66.00	136.00	2,260
2004	159.00	86.00	73.00	3%	68.00	141.00	2,650
2005	163.00	87.00	76.00	5%	72.00	148.00	2,370
2006	168.00	88.00	80.00	5%	75.00	155.00	1,990
2007	174.00	89.00	85.00	6%	79.00	164.00	1,490
2008	181.00	90.00	91.00	7%	85.00	176.00	800
2009	198.00	100.00	98.00	8%	92.00	189.00	1,370
2010	218.00	112.00	106.00	8%	99.00	205.00	2,150
2011	236.00	118.00	118.00	11%	110.00	228.00	1,290
2012	261.00	135.00	126.00	7%	119.00	245.00	2,780
2013	296.00	160.00	136.00	8%	128.00	264.00	5,380
2014	315.00	175.00	140.00	3%	132.00	272.00	7,220
2015	325.00	200.00	125.00	-11%	118.00	243.00	13,690
2016	323.00	204.00	119.00	-5%	112.00	231.00	15,460
2017	334.00	208.00	126.00	5%	118.00	243.00	15,480
2018	343.00	212.00	131.00	4%	123.00	254.00	15,570
2019	353.00	216.00	136.00	4%	128.00	264.00	15,600
2020	364.00	221.00	143.00	5%	134.00	277.00	15,400
Total							123,850

Note: Prices have been rounded to nearest dollar and savings to nearest AU10m.

Source: Table 7.8

Without these "excess" network charges retail electricity prices would have been substantially lower, in FY 2015 for example at AU$243/MWh rather than AU325/MWh, a reduction of 25%. Total cost savings over the period FY 2000 to FY 2020 are estimated to be AU$123.8 billion. Not all of these savings however would have been achievable because the importance of "keeping the lights on" comes at a cost but the analysis does give some indication of the upper bound of what has been known as "gold plating", as discussed in Section 5.6.2.

Chapter 8 Conclusions

Summary

Chapter 8 summarises key differences between types of GHG emission reduction schemes and then brings together the key findings of the model analysis, including the impact of subsidies on stimulating household PV uptake and large-scale renewable energy development, and outcomes if there had been lower subsidy levels. The impact these subsidies has had, and will have in the future, on retail electricity prices is examined as well as the potential for households to benefit from battery storage. The likelihood of Australia meeting its renewable energy and emission reduction targets is discussed. The chapter concludes with research limitations and suggested areas for future research.

8.1 Comparison of GHG emission reduction schemes

Emission reduction schemes differ in many respects including government cost and revenue implications and their effectiveness in achieving emission reduction targets. Carbon pricing ("Price") schemes involve subjective judgement in setting emission reduction baselines but, as with Australia's current DAP scheme, they have the benefit of allowing the auction process to set a carbon price, which might otherwise be set by regulation. Renewable energy ("Quantity") schemes have renewable energy output or emission reduction target clarity and, in the case of Australia's LRET scheme, involve a market price (LGC) mechanism designed to ensure the renewable target is met, although timing issues may result in targets being met over a longer time frame than initially envisaged.

8.2 Desirable structure of emission reduction schemes

Lessons learnt from this research are the need for an integrated approach, when more than one emission reduction scheme has been introduced, and the cost implications of setting scheme parameters unrelated to changing market conditions. In Australia's case, with household PV a more cost-effective outcome would have been likely if FITs had a market price component and were not determined independently by each state.

It is important to have households involved in schemes targeted to reduce emissions, but their demand-side involvement, through higher electricity prices, is not the most effective means of reducing emissions. Emission reductions are most effective if incentives or penalties are targeted at the generation source, rather than where demand occurs. In Australia subsidising renewable energy generation, both for household PV and large-scale renewable energy has been effective, although costly. Substantial emission reductions occurred during the two year carbon pricing period, when gas-fuelled generation replaced coal-fired generation. This occurred at a high cost and begs the question of what lower carbon price might have achieved a similar emissions reduction outcome.

8.3 Household PV summary and conclusions

In Australia, household PV financial incentives have been very successful in stimulating PV activity and hence in reducing GHG emissions, being well in excess of forecasts. This has come at a substantial cost to electricity consumers, particularly in FY 2010 and FY 2011, when FITs were at their highest levels. Policy makers had not anticipated the coincidental high levels of incentives and the drop in the cost of solar panels, by over 50%, as well as the strong interest by households in seeking to take some control of their electricity costs. Modelling suggests that if the level of FITs had been less attractive such that payback periods fell to no lower than five years, the uptake would have been only marginally less but the level of subsidies would have been reduced by AU$1.0 billion, over the period FY 2008 to FY 2014. This could have been possible if FITs had included a market-related reduction, remained within a price range and/or contained an ongoing sliding scale.

Household PV subsidy payments are forecast to cost AU$7.8 billion over the period 2000 to 2020. Substantial emission reductions were achieved which will continue for the life time of the PV panels. Emission reduction costs are estimated to decline from over AU$200 per t CO_2e in FY 2010 to a forecast AU$110 per t CO_2e in FY 2020. These unit costs are higher than in most other parts of the world, but a true comparison requires comparable methods of calculating emission reduction benefits. The reducing unit cost reflects the expiry of attractive FITs on a state by state basis between 2016 and 2028. They are largely responsible for ongoing subsidies in excess of AU$600m pa continuing to 2016 then falling to AU$400m by FY 2020 and beyond.

Australia's targeted 5% reduction in GHG emissions over the period 2000 to 2020 requires the stationary electricity sector to not exceed 191 m t CO_2e in 2020. In FY 2013 the level was 193.1 m t CO_2e, at which time household PV had reduced emissions by 3.0 m t CO_2e. The extra PV reduction of 3.9 m t CO_2e, forecast to result in a FY 2020 PV emissions reductions of 6.9 m t CO_2e, highlights the important role PV will continue to have in assisting Australia to meet its GHG reduction commitments. On an accumulative basis, over the 14 year period from FY 2007 to FY 2020, it is forecast that household PV will reduce GHG emissions by 44.5 m tonnes at a cost of AU$7.9 billion. This is equivalent to households paying in the order of an extra 2.2% on their electricity bills, averaged over the 14 year period from FY 2007 to FY 2020.

Modelling was used to evaluate the outcome if there had been no household PV subsidies. Retail electricity costs would have been substantially lower through no impost from the carbon price, STCs and FITs, but there would still have been a household PV uptake of 1600 MW, or 43% of the total uptake, over the period FY 2008 to FY 2014. This outcome reflects the continuing decline in solar panel costs, savings from reduced domestic consumption and the (comparatively small) FIT that retailers would still pay for electricity exports.

Looking forward, even though export revenue has declined to an average AU6 to 8 cent per kWh, the comparatively low cost of solar panels, reduced by STC savings, combined with the savings from reduced electricity consumption suggests that the interest in household PV will remain strong, although uptake will increasingly reduce as household penetration continues to increase. Modelling suggests that by FY 2020 household PV will total 7,240 MW, of which 4800 MW, that is 66%, would have arisen without subsidies.

8.4 Large-scale renewable energy summary and conclusions

The viability of large-scale renewable energy projects in Australia is largely dependent on grants and LGC payments. LGC prices are set by demand and supply with demand being a reflection of the LRET target. Although agreement on a lower (33,000 GWh) target, inclusive of small-scale renewable energy, was reached between the major political parties in May 2015, the certainty it provided resulted in a substantial increase in LGC prices which is very likely to ensure the 2020 target of 20% of total energy being met from renewable energy sources will be met.

In FY 2014 subsidy-related renewable energy reduced GHG emissions by 13.6 m t CO_2e, being 3.7 m t CO_2e from household PV and 9.9 m t CO_2e from large-scale renewable energy (Table 6.14). By FY 2020 it is expected that the comparative contributions will be 6.9 m t CO_2e and 21.4 m t CO_2e respectively, totalling 28.3 m t CO_2e showing similar growth rates.

Unit emission reduction costs gradually rose to AU$47/t CO_2e in FY 2014 and are expected to increase to AU$80/t CO_2e in FY 2020 as a result of the substantial increase in LGC prices and less effective emission reductions. It is possible that LGC prices may increase above this level in order for the 33,000 MWh LRET target to be met. This is most likely to occur in the lead-up to FY 2020 because projects, in taking time to reach completion, may not have enough time to take advantage of the higher LGC prices to be able to meet pre FY 2020 LRET targets. This will cause LGC prices to spike until such time as new projects come on stream. By FY 2020 LGC prices are unlikely to be at the cap of AU$92.86/MWh as sufficient new large-scale energy projects should have ensured LGC supply is adequate to meet demand.

Wind energy subsidy costs are the lowest, followed by solar energy and then bagasse cogeneration. Hydro energy unit emission costs are also low but their contribution is comparatively small because these comments only relate to subsidised renewable output. Hydro energy, although the largest source of renewable energy at present, provides the lowest level of subsidised renewable energy. Forecasts suggest that wind energy output will overtake hydro energy generation as the largest renewable energy source in several years' time.

8.5 Consideration of Australia's renewable energy and emission reduction targets

Modelling suggests total electricity generation increasing from 224,000 GWh in FY 2001 to 252,000 GWh in FY 2010 and forecast to reach 268,000 GWh in FY 2020 (Table 8.2). These figures represent an increase of 13% in the first 10 years and 6% in the second 10 years highlighting the impact of factors such as renewable energy displacing non-renewable energy and energy conservation in the second period.

Renewable energy output increased from 17,500 GWh in FY 2001 to 37,000 GWh in FY 2010 and forecast to reach 53,600 GWh in FY 2020 (Table 6.14), an overall increase of 36,100 GWh between FY 2001 and FY 2020. Of the 36,100 GWh increase, household PV is forecast to comprise 7,900 GWh and large-scale renewable energy 28,200 GWh.

In FY 2014 subsidy-related renewable energy reduced GHG emissions by 13.6 m t CO_2e, being 3.7 m t CO_2e from household PV and 9.9 m t CO_2e from large-scale renewable energy. By FY 2020 it is expected that the comparative contributions will be 6.9 and 21.4 m t CO_2e respectively, totalling 28.3 m t CO_2e, showing similar growth rates. However the associated subsidy costs are very different, with household PV emission reduction costs of AU$118/ t CO_2e in 2014 *decreasing* to an expected AU$110/ t CO_2e by 2020 and large-scale renewable energy emission reduction costs of AU$47/ t CO_2e in 2014 *increasing* to an expected AU$80/ t CO_2e by 2020. Household PV emission reduction costs are higher but decreasing whereas large-scale renewable emission reduction costs are lower but increasing. The diverse trends reflect high FITs gradually terminating while LGC prices have instead been increasing.

Australia has targets of at least 20% of electricity generation being from renewable energy sources and GHG emission reductions of 5% compared with 2000 levels by 2020. (Clean Energy Regulator, 2012a). The modelling undertaken in this thesis is designed to assist in determining whether these targets will be met and to provide guidance on whether these targets could have been achieved more cost effectively.

Target of 20 % electricity being supplied by renewable energy

The LRET target of 33,000 GWh, being additional renewable energy from base year FY 2000, appears achievable according to the modelling results in this thesis (Table 8.2). The forecast can be considered conservative as no allowance has been made for the results of the DAP auctions. The result is supported by the fact that if the target does not appear achievable the LGC price would rise to its cap of AU92.86/MWh ensuring some seemingly unviable projects proceed. Hence target achievement looks very likely with the real question being, given delays in project implementation, whether the achievement will be in time to meet the 2020 target. Australian Government, Department of Environment, (2015b) concluded that if the revised large-scale generation target of 33,000 GWh was met then the renewable percentage would be 23.5%, being consistent with the conclusions reached in this thesis.

Table 8-1 Renewable energy share of total electricity generation with and without subsidies

FY	Renewable energy output	Non-renewable energy output	Total energy output	Renewable share	Subsidy related renewable energy	Non-subsidised renewable energy output	Non-subsidised renewable share	L/scale renew. output less base year
	(GWh pa)	(GWh pa)	(GWh pa)	(%)	(GWh pa)	(GWh pa)	(%)	(GWh pa)
2001	17,440	206,200	223,640	8%	1,500	15,940	7%	0
2002	17,570	207,300	224,870	8%	1,940	15,630	7%	140
2003	18,530	203,590	222,120	8%	3,280	15,260	7%	1,110
2004	18,800	210,980	229,780	8%	3,340	15,470	7%	1,380
2005	21,030	207,620	228,650	9%	3,710	17,320	8%	3,620
2006	21,880	210,950	232,830	9%	4,020	17,870	8%	4,480
2007	21,440	221,710	243,150	9%	4,780	16,670	7%	4,040
2008	20,740	222,470	243,220	9%	5,990	14,760	6%	3,300
2009	18,100	231,430	249,530	7%	5,690	12,410	5%	540
2010	21,490	230,790	252,280	9%	8,570	12,910	5%	3,620
2011	25,350	227,950	253,300	10%	10,550	14,800	6%	7,060
2012	26,160	223,720	249,890	10%	12,290	13,880	6%	6,590
2013	32,330	217,430	249,760	13%	16,430	15,900	6%	11,760
2014	36,570	211,720	248,300	15%	19,770	16,800	7%	15,300
2015	39,840	210,500	250,340	16%	22,660	17,180	7%	17,870
2016	42,470	213,550	256,020	17%	25,320	17,140	7%	19,830
2017	45,080	214,600	259,680	17%	27,940	17,140	7%	21,810
2018	47,920	214,650	262,570	18%	30,770	17,140	7%	24,100
2019	50,440	214,700	265,140	19%	33,300	17,140	6%	26,170
2020	52,890	214,750	267,640	20%	35,750	17,140	6%	28,250

Note: Figures have been rounded to nearest 10 GWh pa.

Source: Table 7.5, Table 7.6, and AEMO (2015b)

Target of 5% reduction in GHG emissions in 2020 compared with 2000

Australia's targeted 5% reduction in GHG emissions in FY 2020 requires total emissions to reduce from 565 m t CO_2e in 2000 to 537 m t CO_2e in 2020, including the electricity sector's emissions reducing from 176 m t CO_2e in 2000 to 167 m t CO_2e in 2020. Latest forecasts (Australian Government, Department of Environment, 2015d) show electricity sector emissions reaching 187 m t CO_2e by 2020, being 21 m t CO_2e above implicit electricity sector targeted levels, but substantially below previous electricity sector forecasts due to the inclusion of expected DAP auction outcomes. It is the DAP auction outcomes that are also expected to enable Australia to achieve its overall emission reduction target. The DAP verification process, to be undertaken in 2016 will be very important in substantiating the accuracy of these figures.

Modelling in this thesis suggests household PV will reduce GHG emissions by 6.9 m t CO_2e in FY 2020 with large-scale renewable energy contributing 21.4 m t CO_2e, a total of 28.3 m t CO_2e. Modelling does not include DAP outcomes, which would increase these figures materially. As an indication the DAP is reported (www.CleanEnergyRegulator.gov.au) to have contracted abatement contracts of 93 m t CO_2e during 2015, but these figures have yet to be verified. There is also the issue that abatement contract possibilities may diminish over time.

Over the 20 years to FY 2020 the total cost of subsidies to achieve these emission reductions is expected to be nearly AU$20 billion. As almost all the subsidy payments are recovered in retail electricity prices, the subsidy cost is equivalent to households paying in the order of an extra 2.2% on their electricity bills, averaged over the 14 year period from FY 2007 to FY 2020.

Without subsidies, very little large-scale renewable energy growth would have occurred between FY 2000 and FY 2020 but almost 50% of household PV is likely to still have eventuated. Emission reductions would have totalled only 3.0 m t CO_2e (2.4 m t CO_2e from household PV and 0.6 t CO_2e from large-scale renewable energy) compared with the forecast 23.9 m t CO_2e, a reduction of 20.9 m t CO_2e. Whether this outcome would materially affect Australia meeting its emission reduction target is largely dependent on emission reduction activities in other areas, reflecting the electricity sector being responsible for only 40 to 45% of total emissions, nevertheless a 20.9 m t CO_2e emission reduction difference could be material.

Differing comments have been made on the likelihood of Australia achieving its targeted level of emission reductions. According to Australian Government, Department of Environment (2015c) Australia is on track to achieve GHG emission reductions of at least 5% below 2000 levels by

2020. Inclusion of the DAP reductions, estimated to total 431 m t CO_2e by 2020, will be a material contribution. Expectation of the target being met is however not a unanimous view with UNEP (2014) commenting that four parties including Australia "are likely to require further action and/or purchased offsets to meet their pledges, according to government and independent estimates of projected national emissions in 2020" (UNEP, 2014, p xix). Shahiduzzam et al (2015), in analysing components of emission reductions in Australia, commented "the unconditional reduction of emissions by 5% by 2020 from the 2000 level will really be quite a daunting task for Australia" (Shahiduzzam et al, 2015, p 100).

8.6 Imposts and opportunities for households

Households experience costs burdens arising from renewable energy but also have opportunities available to make financial gain and contribute towards environmental improvements.

Retail price subsidy impact

Retail electricity prices are substantially higher than they would otherwise have been without the inclusion of subsidies for renewable energy and the two years of a carbon price. If none of these subsidies had applied in FY 2015 the retail electricity price would have been AU$315.00/MWh rather than AU$325.00/MWh. With no subsidies at all during any of the 15 years from FY 2000 to FY 2015 the retail electricity price in FY 2015 would have been AU$182.00/MWh rather than AU$325.00/MWh, a reduction of 44%. Similarly the retail electricity price for FY 2020 forecast to be AU$364.00/MWh would instead be AU$344.00/MWh without subsidies in FY 2020 and AU$127.00/MWh without any subsidies during the 20 year period, a decrease of 65%. This highlights the fact that although society may agree there is an emissions reduction need, penalties or incentives are necessary to ensure there is a price signal to react to and that there are few, if any, free riders (as few parties are exempt any of the subsidies).

Energy conservation

The role of households in helping Australia meet its emission reduction targets is becoming increasingly noticeable, reflected in the increasing belief in the reality of climate change, the uptake of energy efficient appliances, the substantial uptake of household PV and the electricity demand response to increasing retail electricity prices. Shahiduzzam et al (2015) observed the potential of energy efficiency in commenting that "energy efficiency played a dominant role in the measured 17% reduction in CO_2e emissions aggregate intensity in Australia over the period 1978-2010".

Wholesale market opportunities may become available in the future that allow households to participate at the wholesale level as well as the retail level. For example the DAP scheme which took effect in early 2015 is mainly targeted at commercial enterprises but this may be expanded to enable households to participate. The carbon offset scheme allows approved parties and approved products to create carbon offsets for purchase by parties with emission reduction liabilities, such as those that have become part of the DAP auction. As mentioned in Australian Government, Department of Environment (2010) approved products include carbon reductions from tree planting and firing of land fill emissions, with many other opportunities that could be provided if schemes such as this were given more prominence. An indication of consumer preferences for policy instruments was canvassed in a survey of 245 executives by the Carbon Market Institute (2014) resulting in vehicle emission and energy standards being most preferred, followed by the RET target and a domestic carbon offset scheme ahead of another eight choices further supporting the views above.

Battery storage

The fast developing market advance of cheaper batteries will create incentives for Australian households to further reduce GHG emissions with another upsurge expected in household PV. For Australian households already with PV the payback period is comparatively high if their PV is the most common size of 1.5 kW to 3.0 kW, being at least 12 years. The payback period falls substantially for households with PV systems in excess of 4kW because PV exports increase at a proportionately faster rate with PV system size, and battery costs exhibit substantial economies of scale. Although the payback period is currently about 11 years it is expected to eventually fall to nearly five years. Based on the experience with household PV a five year payback period will result in a substantial uptake of battery storage systems. Unlike household PV this mini boom is not driven by subsidies, although subsidies were largely responsible for the initial household PV boom.

At the household level there has been much research recently relating to the development of models to find the optimal mix of solar/wind and battery storage for given load profiles. Fast developing technologies and greater economies of scale in the future suggest that eventually such “integration” models may become available for use by households to assist them in cost effectively integrating their energy choices.

8.7 Limitations of research

The 20 year database used in this thesis is from Australia published information gathered over the years FY 2000 to FY 2015 plus forecast information for the subsequent five years. Forecasts are based on assumptions which have been rapidly changing and need constant updating. Data for household PV analysis was available in more detail than for large-scale renewable energy and hence more reliable. Household FIT payments were built up from (1) state FITs, noting access to FITs in some states extended beyond announced expiry dates, and from (2) state PV installations. Although the outcomes were matched against various press releases of FIT payments, and found to be comparable, further analysis would be desirable.

Recent data shows the rapid pace of developments in the areas of renewable energy and conservation: faster than most forecasters anticipated. In particular household PV has grown faster than forecast, total energy consumption has declined faster than anticipated, household average electricity household consumption is lower than expected and future retail electricity tariffs are likely to be lower than expected. These events do not impact on the key year of focus, being household PV over the period FY 2000 to FY 2014, or on the broad conclusions reached but the speed of change means that constant updating is required. Most importantly these changes will impact forecasts over the period FY 2020 to FY 2030, not examined in this thesis.

A key development considered important enough to incorporate at a late stage, was the recent rapid rise in LGC prices, stimulating renewed interest in large-scale renewable energy projects. At the time of writing LGC prices were still increasing, making large-scale renewable energy projects more attractive and increasing the level of subsidies to be paid by a electricity consumers.

From a modelling viewpoint the key data limitation relates to reconciling renewable energy growth data to the creation of LGCs, as shown in the REC Registry. There are a number of reasons for this, particularly the fact that LGC data is for calendar years and model data and BREE output data are for financial years. In addition renewable energy baselines for each renewable energy type, showed unexplainable variations which the CER could not explain and warrants further investigation. This required approximations of how numbers of LGCs were determined but not to the extent that they affected the broad conclusions reached.

One development has unwittingly made household PV more attractive. Reduced electricity consumption has resulted in more electricity being exported rather than used to offset domestic consumption, increasing FIT returns in excess of retail tariff rate savings. This may help explain why current growth in household PV has been stronger than most forecasters had expected, and is another area that could be further explored.

8.8 Policy implications of thesis results

The results of this thesis highlight a range of future policy issues.

The undertakings by Australia in seeking to meet emission reduction targets and renewable energy targets need policies that transparently show how these targets are expected to be achieved including the expected relationship between these policies, including ensuring "double dipping" does not occur and how targets at different future points of time will be met. A concern, already experienced by households in regard to PV, is an assurance that ongoing incentives will remain in place for a minimum time period. The history of FITs suggests that policies are better determined nationally than on a state by state basis and that there is bipartisan support.

There are consequent market implications of the growth in renewable energy that will be highlighted further as the growth in renewable energy continues. Network companies need to ensure there is adequate capacity to meet situations of high renewable energy output when the direction of electricity flows reverse and in times when there is volatility in wind generation when backup, typically gas-fired or hydro, generation is required. The extent to which new network capital expenditure is required will become a testing exercise for the associated regulator, the AER.

Generator revenues will be impacted by their bidding behaviour. Renewable energy with very low operating costs, can provide low priced bids but to the extent to which such bids set the pool price, all generators pool price revenue will be reduced (Wilkie, 2015). This is the classic marginal cost pricing dilemma which has resolution in bidders raising their bids, when the market allows, that is when there is little competition, to ensure additional revenue is secured in these times to provide adequate revenue (that is for capital replacement) over longer time periods, such as annually. This may test authorities such as the Australian Competition and Consumer Commission who have in the past (Burtt, 2009) investigated the bidding behaviour of generators to ensure there has been no abuse of market power.

The structure of franchise tariffs is a key market efficiency issue because of the need to provide market participants with price signals that reflect underlying market costs. This particularly applies to demand side management and will be important in the future with the expected increase in electric motor vehicles. Flat franchise tariffs do not encourage load shifting to lower cost periods; nor do they provide the incentive for electric vehicle charging to occur outside the period of peak demand (Young et al, 2015). The structure of franchise tariffs differs by state and ideally need to be the type of three part tariff as in NSW on a national level.

There is also the network issue of ensuring network companies receive adequate revenue as a result of increasing number of PV households reducing electricity imported from the grid, and in extreme cases going "off grid" (Oliva and MacGill, 2013). Innovative tariffs and a realistic time period for adjustment will be required, possibly again involving the AER (as mentioned three paragraphs earlier).

8.9 Suggested areas for future research

There are some areas for future research in an Australian context, which would add value to this thesis, being mainly an expansion of research already undertaken. Firstly there are areas related to data trends and comparative economics associated with achieving improved efficiencies from household PV. Solar emission reduction benefits are sensitive to levels of household electricity consumption and to load shape. The extent to which household electricity consumption continues to decline will alter the economics through changing the offset and export balance. The continued roll out of half-hourly meters, with associated data availability, and more households having access to wholesale market prices, or surrogates such as three part pricing, will assist in determining the long-term value of PV. The economics of these developments should be better understood.

Secondly there is value in monitoring the expiry of FITs by Australian state as it is possible, with declining battery costs, that there will be an upsurge both in battery purchases and (again) in household PV. Being prepared for this may help avoid another boom and bust outcome.

Thirdly there is expected to be increased interest in Australia in customised methods to determine the optimal integration of wind generation, solar generation and electricity storage associated with individual demand profiles. This could occur at both the household and wholesale level. It is likely that standard software might eventually be available at the household level, coinciding with reduced battery storage costs, to allow households to better utilise renewable energy generation. Households may attempt to go "off-grid" but the eventual reality of the risk of renewable-energy related power shortages may prove to be a limiting factor. A better appreciation of these events will be important for market operators and network companies.

Fourthly, in response to the increased interest by Australian households to participate in conservation measures, there is value in determining means by which households can contribute to emissions reductions. This could occur at the macro level in the form of demand reduction aggregation or at the micro level through greater use of more energy efficient appliances and through households being provided with the ability to respond to two or three part pricing.

The structure of any FIT scheme in future needs careful consideration as this thesis suggests. The dilemma is that FIT schemes need to provide investors with enough certainty to invest while still giving policy makers some forward pricing discretion. A critical aspect is whether FIT changes are applied at the decision-making stage or on an ongoing basis, being particularly relevant for households with PV installed. If the latter is adopted households are forced to make investment decisions in an uncertain future financial climate which, as witnessed in NSW in Australia, could have a strong public backlash.

On a broader scale there is a need for more research into the relationship between emission reduction schemes, their comparative timing and the comparative cots involved. The need for investment certainty needs to be balanced against the ongoing cost-effectiveness of subsidies, and whether they are paid for by electricity consumers or sourced from states or the Commonwealth Government. Included in the mix should be realisation that reduced GHG emissions are more cost-effectively achieved if incentives or penalties are applied at the source of generation rather than consumers of electricity. This is evidenced in electricity consumers' comparatively low price elasticity of demand.

References

Ackerman, F. Stanton, E. A., Bueno, R. (2010), CRED: A new Model of Climate and Development, *Ecological Economics* 85 (2013) 166-176.

Ackerman, F., Bueno R. (2011), *Use of McKinsey Abatement Cost Curves for Climate Economics Modeling* (25 January 2011) Stockholm Environment Institute Working Paper WP-US-1102. Accessed from www.sei-us.org

ACT Government. (2015), *Review of the Electricity Feed-in (Renewable Energy Premium) Act 2008*, August 2015, Environment and Planning Directorate, ACT Government. Accessed March 2016 from www.legislation.act.gov.au

AER. (2015), *AER Ruling on Network Charges and Final decision: Essential Energy (distribution) 2015-19*. Accessed November 2015 from www.aer.gov.au/networks-pipelines/determinations

AG. (2011), *Clean energy Bill 2011*, Australian Government. Accessed from www.comlaw.gov.au

Agnew, S., Dargusch, P. (2015). Effect of residential solar and storage on centralized electricity supply systems, *Nature Climate Change 5* 315-318 (2015).

Aldy, J. E., Stavins, R. N. (2012), Climate Negotiators Create an Opportunity for Scholars, *Science, Vol 337*, 31, August 2012. Accessed 2014 from www.sciencemag.org

Antonelli, M., Desideri, U. (2014a), Do feed-in tariffs drive PV cost or vice versa? *Applied Energy 135 (2014)* 721-729.

Antonelli, M., Desideri, U. (2014b), The doping effect of Italian feed-in tariffs on the PV market, *Energy Policy 67 (2014)* 583-594.

APVI. (2016), *Mapping Australian Photovoltaic installations*. Australian PV Institute, June 2016. Accessed October 2016 from www.pv-map.apvi.org.au

Ashurst. (2012), *Linking Australia's Carbon Pricing Mechanism to the European Union Emissions Trading System*, presentation by Ashurst staff on 2 November 2012. See also Energy & Law Update – October 2012 at www.ashurst.com

Atia, D.M., Fahmy, F. H., Ahmed, N. M., Dorrah, H. T. (2014), Optimization and feasibility analysis of PV/wind/battery hybrid energy conversion, *International Journal of Electrical, Computer, Electronics and Communication Engineering, Vol 8(5)* 2014.

Austin, M. (2007), The Business of Carbon Trading, *Renewable Energy Focus, Vol 8 Issue 5*, 60-62, 64.

AEMC. (2013), *Electricity Price Trends Final: Report. Possible future retail electricity price movements: 1 July 2012 to 30 June 2015*, 22 March 2013. Accessed May 2014 from www.aemc.gov.au

AEMC. (2015), *Integration of Energy Storage. Regulatory Implications*. Discussion Paper 9 October 2015. Accessed December 2015 from www.aemc.gov.au

AEMO. (2012), *Rooftop PV Information Paper, National Electricity Forecasting 2012*, AEMO. Accessed in May 2014 from www.aemo.com.au

AEMO. (2013), *Executive Briefing: 100% renewables study – Draft Modelling Outcomes*, Australian Electricity Market Operator, 28 March 2013. Accessed 2014 from www.climatechange.gov.au

AEMO. (2014), Web site with long-term series of half-hour wholesale electricity prices and load data. Accessed in February 2014 from www.aemo.com.au

AEMO. (2015a), *Emerging Technologies Information Paper, National Electricity Forecasting Report*, Published: June 2015. Accessed October 2015 from www.aemo.com.au/News-and-Events/News/News/2015

AEMO. (2015b), *National Electricity Forecasting Report Overview, For the National Electricity Market*, June 2015. Accessed in December 2015 from www.aemo.com.au

AEMO. (2016), *Forecasting Methodology Information Paper 2016 National Electricity Forecasting Report*, Published July 2016. Accessed October 2016 from www.aemo.com.au/Electricity/National-Electricity-Market-NEM

ARENA. (2013), *Australian Energy resource assessment – Chapter 9 – Wind Energy*, Australian Renewable Energy Agency. Accessed December 2015 from www.arena.gov.au/files/2013/08/Chapter 9–wind-energy

ASMC. (2014), Australian Sugar Mill Council submission to RET Review Panel, 16 May 2014. Accessed September 2015 from www.climatechangeauthority.gov.au/files

Ausgrid. (2014), *Solar home electricity data. Three years of half-hour electricity data for 300 solar homes (1 July 2010 to 30 June 2013).* Accessed from www.ausgrid.com.au/common/About-us/corporate - information

Australian Bureau of Family Studies. (2014), *Family facts and figures: Australian households.* Accessed in July 2014 from www.aifs.gov.au/institute/info/charts

Australian Bureau of Statistics. (2013), *Household Energy Consumption Survey, Australia: Summary of Results*, *2012*, Australian Bureau of Statistics Media Release 24 September 2013. Accessed December 2015 from www.abs.gov.au/ausstats/abs@nsf/Lookup/4760.0Media+Release100002012

Australian Government Climate Change Authority. (2012), *Renewable Energy Target Review, Issues Paper, August 2012*. Accessed June 2014 from www.abareconomics.com

Australian Government Climate Change Authority. (2014), *Reducing Australia's Greenhouse Gas Emissions-Targets and Progress Review. Final Report, February 2014.* Accessed March 2016 from www.climatechangeauthority.gov.au

Australian Government Department of Climate Change and Energy Efficiency, (2012a), *Australia's Emissions Projections 2012*. Accessed May 2013 from www.climatechange.gov.au

Australian Government Department of Climate Change and Energy Efficiency. (2012b), *Securing a Clean Energy Future: Implementing the Australian Government's Climate Change Plan.* (Also known as the Clean Energy Futures Plan). Statement by Greg Combet, Minister for Climate Change and Energy Efficiency 8 May 2012. Accessed October 2016 from www.budget.gov.au/2012-13/content/ministerial-statements

Australian Government, Department of Environment. (2010), *National carbon offset standard*, Accessed November 2015 from www. Environment.gov.au/climate-changed/carbon-neutral

Australian Government, Department of Environment, (2013), *Australian National Greenhouse Accounts, September Quarter 2013*. Accessed December 2013 from www.climatechange.gov.au/emissions

Australian Government, Department of Environment. (2015a), *Australia's Emission Projections 2014-2015, March 2015*. Accessed November 2015 from www.climatechange.gov.au/emissions

Australian Government, Department of Environment. (2015b), *The Renewable Energy Target (RET) scheme*. Accessed November 2015 from www.environment.gov.au/climate-change/renewable-energy-target-scheme

Australian Government, Department of Environment. (2015c), *Australia's abatement task: tracking to 2020. FACT SHEET*. Accessed November 2015 from www.environment.gov.au/climate-change

Australian Government, Department of Environment. (2015d), *Tracking to 2020. An interim update of Australia's greenhouse gas emissions projections, December 2015.* Accessed March 2016 from www.environment.gov.au/climate-change/emissions- projections

Australian Government, Department of Industry and Science. (2015a), *Australian Energy Update*, 2015, Office of the Chief Economist. Accessed November 2015 from www.industry.gov.au/OCE

Australian Government, Department of Industry and Science. (2015b), *FACT SHEET What causes changes in electricity prices?* Accessed December 2015 from www.industry.gov.au/Energy/Energy-information

Australian Government, Department of Industry, Innovation and Science. (2015), *Energy in Australia, 2015*, Office of the Chief Economist, Accessed February 2016 from www.industry.gov.au/OCE

Australian Government. (2014), *Emissions Reduction Fund White paper, April 2014*. Accessed October 2014 from www.environment.gov.au/climate-change

Australian Government Productivity Commission. (2011), *Carbon Emission Policies in Key Economies*, Research Report, Canberra, May 2011. Accessed May 2014 from www.pc.gov.au

Australian PVA. (2011), *Australian PV Survey Report 2011*, APVA, May 2012, Australian PV Association. Accessed June 2014 from www.apva.org.au

Australian PV Association. (2012), *APVA Response to the Climate Change Authority Renewable Energy Target Review Issues Paper*, August 2012, Australian PV Association.

Australian PV Institute. (2015), *Market Analysis. Australian PV market since April 2015.* Accessed November 2015 from www.pv-map.apvi.org.au/analyses

Avi-Yonah, R., S., Uhlmann, D., M. (2009), Combating Global Climate Change: Why a carbon Tax is a better response to Global Warming than Cap and trade, *Stanford environmental Law Journal, vol 28, No. 3.*

Ayompe, L, M., Duffy, A. (2013), Feed-in tariff design for domestic scale grid-connected PV systems using high resolution household electricity demand data, *Energy Policy 61 (2013)* 619-627

Bahadori, L., Nwaoha, C. (2013), A review on solar energy utilisation in Australia, *Renewable and Sustainable Energy Reviews 18 (2013)* 1-5.

Bakhtyar, B., Ibrahim, Y., Alghoul, M. A., Aziz, N., Fudholi, A., Sopian, K. (2014), Estimating the CO_2 abatement cost: Substitute Price of Avoiding CO_2 emission (SPAE) by renewable energy's feed in tariff in selected countries, *Renewable and Sustainable Energy Reviews 35 (2014)* 205-210.

Balcombe, P., Rigby, D., Azapagic, A. (2015), Energy self-sufficiency, grid demand variability and consumer costs: Integrating solar PV, Stirling engine CHP and battery storage, *Applied Energy 155 (2015)* 393-408.

Basu, P., Butler, J., Leon, M. A. (2011), Biomass co-firing options on the emission reduction and electricity generation costs in coal-fired plants, *Renewable Energy 36 (2011)* 282-288

Bazilian, M., Onyeji, I., Liebreich, M., MacGill I., Chase, J., Shah, J., Gielen, D., Arent, D., Landfear, D., Zhengrong, S. (2013), Re-considering the economics of photovoltaic power, *Renewable Energy 53 (2013)* 329-338.

Bertoldi, P., Rezessy, S., Langniss. O., Voogt. M. (2005), *White , Green and Brown Certificates: how to make the most of them?* Paper 7203, EC Joint Research Center. Accessed July 2014 from www.ewc

Bertram, G., Terry, S. (2010), *The Carbon Challenge: New Zealand's Emission Trading Scheme*, Bridget Williams Books.

Bloomberg. (2014), *Bloomberg New Energy Finance releases Q3 renewable energy investment report.* 6 October 2014. Accessed November 2014 from www.renewableenergyfocus.com

Bloomberg. (2016), *Clean Energy Investment in 2016 Undershoots Last Year's Record,* Bloomberg press release 14 July 2016. Accessed October 2016 from www.about.brief.com/press-releases

Bode, S., Michaelowa. (2001), *Avoiding Perverse Effects of Baseline and Investment Additionality Determination in the case of Renewable Energy Projects*, HWWA Discussion Paper 148, Hamburg Institute of International Economics, ISSN 1616-4814.

Bonte, W., Nielen, S., Valitov, N., Engelmeyer, T. (2015), Price elasticity of demand in the EPEX spot market for electricity-New empirical evidence, *Economic Letters 135 (2015)* 5-8.

Branker, K., Pathak, M.J.M., Pearce, J.M. (2011), A review of solar photovoltaic levelized cost of electricity, *Renewable and Sustainable Energy Reviews 15 (2011)* 4470-4482.

BREE. (2013), *Energy in Australia – May 2013*. Australian Government Bureau of Resources and Energy Economics. Accessed June 2014 from www.bree.gov.au

BREE. (2015), *Australian Energy Projections to 2049-50* Australian Government Bureau of Resources and Energy Economics. Accessed December 2015 from www.bree.gov.au

Brohe, A., Eyre, N., Howarth, N. (2009), *Carbon Markets An International Business Guide.* Earthscan. www.earthscan.co.uk

Buckman, G., Diesendorf. (2010a), Design Limitations in Australian Renewable Energy Policies, *Energy Policy 38 (2010)* 3365-3376.

Buckman, G. Diesendorf, M. (2010b), Addendum to “Design Limitations in Australian Renewable Energy Policies” , *Energy Policy 38 (2010)* 7539-7540.

Buckman, G., Sibley, J., Bourne, R. (2014), The large-scale solar feed-in tariff auction in the Australian Capital Territory, Australia, *Energy Policy 72 (2014)* 14-22.

Burer, M. J., Wustenhagen, R. (2009), Which renewable energy policy is a venture capitalist’s best friend? Emperical evidence from a survey of international cleantech investors, *Energy Policy 37 (2009)* 4997-5005.

Burke, P. J. (2016), *Undermined by adverse selection: Australia’s Direct Action abatement subsidies*, CCEP Working Paper 1605, April 2016. Crawford School of Public Policy, The Australian National University. Accessed October 2016 from www.ccep.crawford.anu.edu/sites/default/files/uploads

Burniaux, J-M., Chateau, J., Dellink, R., Duval, R., and Jamet, S. (2009), *The Economics of Climate Change Mitigation: How to Build the Necessary Global Action in a Cost-effective Manner* OECD Economics Department Working Papers No. 701 Accessed October 2013 from www.oecd.org

Burtt, D. (2009), *Electricity Deregulation and Vertical Integration*, Lambert Academic Publishing AG & Co. KG, Germany.

Burtt, D., Dargusch, P. (2015), The Cost-effectiveness of Household Photovoltaic Systems in Reducing Greenhouse Gas Emissions in Australia: Linking Subsidies with Emission Reductions, *Applied Energy 148 (2015)* 439-448

Bushnell, J., Chen, Y. (2009), *Regulation, Allocation, and Leakage in Cap and Trade Markets for CO2*, NBER Working Paper No. 15495.

Byrnes, L., Brown, C., Foster, J., and Wagner, L. (2013), Australian renewable energy policy: barriers and challenges, *Renewable Energy 60 (2013)* 711-721.

C2ES. (2012), *California Cap-and Trade Program Summary Table* Centre for Climate and Energy Solutions, Nov 2012. Accessed October 2014 from www.c2es.org

Carbon Market Institute. (2013), *The State of the Australian Carbon Market 2013.* Accessed from www.carbonmarketinstitute.org

Carbon Market Institute. (2014), *The Australian Emissions Reduction Survey – 2014 Report of Key Findings*, November 2014. Accessed November 2014 from www.dpmc.gov.au

Cheng, C-C. and Lai, Y-B. (2011), Does a Stricter Enforcement Policy Protect the Environment? A Political Economy Perspective, *Resource and Energy Economics* Vol 34 (2012), 431-441.

Cherrington, R., Goodship, V., Longfield, A., Kirwan, K. (2013), The feed-in tariff in the UK: A case study focus on domestic photovoltaic systems, *Renewable Energy 50 (2013)* 421-426.

Chiang, S. J., Chang, K.T., Yen, C. Y. (1998), Residential photovoltaic energy storage system, Industrial Electronics, *IEEE Transactions on, Vol 45 Issue 3* 385-394.

Chichilnisky C., and Block, W. (2000), "Environmental Markets: Equity and Efficiency" Book Review, 2004, *The Quarterly Journal of Austrian Economics, Vol 7. No. 2 (Summer 2004)*, 91-97.

Chomitz, K. M. (1998), *Baselines for Greenhouse Gas Reductions: Problems, Precedents, Solutions*, prepared for the Carbon Offsets Unit, World Bank by Kenneth M. Chomitz, Development Research Group, World Bank, 16 July 1998. Accessed June 2015 from www.eldis.org

Cian, E.D., Tavoni, M. (2012), Do technology externalities justify restrictions on emissions permit trading?, *Resource and Energy Economics 34 (2012)* 624-646.

Ciarreta, A., Espinosa, M.P., Pizarro-Irizar, C. (2014), Is green energy expensive? Emperical evidence from the Spanish electricity market, *Energy Policy 69*, 205-215.

Clean Energy Council. (2012), *Clean Energy Australia, Report 2012*. Accessed October 2014 from www.cleanenergycouncil.org.au

Clean Energy Council. (2013), *Clean Energy Australia, Report 2013*. Accessed June 2014 from www.cleanenergycouncil.org.au

Clean Energy Council. (2015), *Clean Energy Australia Report 2015*. Accessed October 2016 from www.cleanenergycouncil.org.au

Clean Energy Regulator. (2012a), *About the Renewable Energy Target,* Clean Energy Regulator, Australian Government. Accessed June 2014 from www.ret.cleanenergyregulator.gov.au

Clean Energy Regulator. (2012b), *Statement of Intent*, Clean Energy Regulator, Australian Government. Accessed December 2014 from www.cleanenergyregulator.gov.au

Clean Energy Regulator. (2015), *Renewable Energy Target 2014 Administrative Report,* Clean Energy Regulator, Australian Government. Accessed December 2015 from www.cleanenergyregulator.gov.au

Climate Change Authority. (2014), *Reducing Australia's Greenhouse Gas Emissions: Targets and Progress- Final Report.* February 2014. Accessed October 2016 from www.climatechangeauthority.gov.au/reviews

Cludius, J. Forrest, S., MacGill, I. (2014), Distributional effects of the Australian Renewable Energy Target (RET) through wholesale and retail electricity price impacts, *Energy Policy, 71, August 2014,* 40-51.

Coase R.H. (1960), The Problem of Social Cost, *Journal of Law and Economics Vol 3(1),* 1-44.

Combet, G. (2012), *Australia Joins Kyoto Protocol Second commitment as World on Track to 2015 Climate Change Agreement*, Joint Media Release 329-12, 2 December 2012. Accessed from www.climatechange.gov.au

CORE. (2011), *British* Columbia*: Emission Offsets Regulation,* Stockholm Environment Institute. Accessed January 2015 from www.env.gov.bc./cas/mitigation/ggrta/offsets_reg.html

Couture, T., Gagnon, Y. (2010), An analysis of feed-in tariff remuneration models: Implications for renewable energy investment, *Energy Policy 38*, 955-965.

CSIRO. (2014), *Australian electricity market analysis report to 2020 and 20130*, Final Draft. For the International Geothermal Expert Group, Energy Flagship. Accessed November 2015 from www.csiro.au

Danchev, D., Maniatis, G., Tsakananikas, A. (2010), Returns on investment in electricity producing photovoltaic systems under de-escalating feed-in tariffs: The case of Greece, *Renewable and Sustainable Energy Reviews Vol 14 (1) January 2010* 500-505.

de la Hoz, J., Martin, H., Ballart, J., Monjo, L. (2014), Evaluating the approach to reduce the overrun cost of grid connected PV systems for the Spanish electricity sector: Performance analysis of the period 2010-2012, *Applied Energy 121 (2014)* 159-173.

de La Tour, A., Glachant, M., Meniere, Y. (2013), Predicting the costs of photovoltaic solar modules in 2020 using experience curve models, *Energy 62 (2013)* 341-348.

Delucchi, M., Jacobson, M. (2011), Providing all global energy with wind, water, and solar power, Part II; Reliability, system and transmission costs, and policies, *Energy Policy 39 (2011)* 1170-1190.

Dolev, D. (2015), *Tesla Battery Costs Could drop by 50%+ with improved Cell Chemistry and Gigafactory*, posted 24 September 2015. Accessed December 2015 from www.teslarati.com/tesla-battery-costs-drop-50-gigafactory

Dominguez, R., Baringo, L., Conejo, A. J. (2012), Optimal offering strategy for a concentrating solar power plant, *Applied Energy 98 (2012)* 316-325.

Dusonchet, L., Telaretti, E. (2015), Comparative economic analysis of support policies for solar PV in the most representative EU countries, *Renewable and Sustainable Energy Reviews, 42 (2015)* 986-998.

Ecogeneration. (2009), *Cogen a Sweet Success, Ecogeneration*, January/February 2009. Accessed December 2015 from www.ecogeneration.com.au.

Edis, T. (2014), *Australia's Micro-grid Opportunity*, Climate Spectator. 21 January 2014 Accessed June in 2014 from www.businessspectator.com.au/article/2014/1/21/renewable-energy/australias-micro-grod-opportunity

Edmonds, J., Wise, M., Barns, D., W. (1995), Carbon Coalitions. The cost and effectiveness of energy agreements to alter trajectories of atmospheric carbon dioxide emissions, *Energy Policy, Vol 23, no. 4/5* pp 309-335.

Ekren, O., Ekren, B.Y. (2010). Size optimization of a PV/wind hybrid energy conversion system with battery storage using simulated annealing, *Applied Energy 87 (2010)* 592-598.

Elliston, B., MacGill, I., Diesendorf, M. (2010), *Grid parity: A potentially misleading concept?* Solar2010, the 48th AuSES Annual Conference 1-3 December 2010, Canberra, ACT, Australia. Accessed October 2016 from www.ceem.unsw.ed.au/sites/default/files/upload/publications

Elliston, B., MacGill, I., Diesendorf, M. (2013), *Comparing Least Cost Scenarios for 100% renewable Electricity with Low Emission Fossil Fuel Scenarios in the Australian National Electricity Market,* 21 August 2013. Accessed December 2015 from www.ies.unsw.edu.au

Energymatters. (2014). Web site providing ongoing STC market prices. Accessed on an ongoing basis from www.energymatters.com.au

Energy Supply Association of Australia. (2010), Energy Supply Association of Australia, *Electricity Gas Australia.* Annual publication

Energy Supply Association of Australia. (2014), Energy Supply Association of Australia, *Electricity Gas Australia.* Annual publication

Energy Supply Association of Australia. (2013). *ESAA fact sheet: electricity price growth*. Accessed December 2013 from www.esaa.com.au/policy/electricity_price_increases_FactSheet_1_1_1

Espey, J. A., Espey, M. (2004), "Turning on the Lights: A Meta-Analysis of Residential Electricity Demand Elasticities", *Journal of Agricultural and Applied Economics, 36, 1 (April 2004):* 65-81.

Evans, C. (2013), *Government Celebrates Carbon Schemes*, Canberra press release 1 January 2013, Power Industry News 821, 14 January 2013, p 20. Subscription publication, Editor Bruce Bertram, pin@bigpond.net.au

Fais, B., Blesl, M., Fahl, U., Vob, A. (2014), Comparing different support schemes for renewable electricity in the scope of an energy systems analysis, *Applied Energy 131 (2014)* 479-489.

Fan, S., Hyndman, R.J. (2011), The price elasticity of demand in South Australia, *Energy Policy 39 (2011)* 3709-3719.

Feijoo, F., Das, T. K. (2014), Design of pareto optimal CO_2 cap-and-trade policies for deregulated electricity networks, *Applied Energy 19 (2014)* 371-383.

Feuerriegel, S., Neumann, D. (2014), Measuring the financial impact of demand response for electricity retailers, *Energy Policy 65*, 359-368.

Fischer, C. (2005), Project-based mechanisms for emission reductions: balancing trade-offs with baselines, *Energy Policy 33 (2005)* 1807-1823.

Fischer, C., Newell, R.G. (2008), "Environmental and technology policies for climate mitigation", *Journal of Environmental Economics and Management, 55 (2008)* 142-162.

Fokaides, P.A., Kylili, A. (2014), Towards grid parity in insular energy systems: The case of photovoltaics (PV) in Cyprus, *Energy Policy 65*, 223-228.

Frankel, P. (2012), Renewable Energy Coming of Age, *The Journal of the International Energy Agency, Issue 2 – Spring 2012.*

Fraser, B. (2015), *Some Observations on Australia's Post-2020 Emissions Reduction Target*. Statement by Chair of Australian Government, Climate Change Authority, Mr Bernie Fraser, 14 August 2015. Accessed October 2016 from www.climatechangeauthority.gov.au/sites

Frontier Economics. (2012), *Market value of solar PV exports*. A final report prepared for IPART. March 2012. Accessed June 2014 from www.frontier-economics.com

Frontier Economics. (2015), *Electricity market forecasts: 2015* A Report prepared for the AEMO (AEMO): Final, April 2015. Accessed November 2015 from www.aemo.com.au/electricity/planning/forecasts

Fthenakis, V.M., Kim, H.C., Alsema, E. (2008), Emissions from Photovoltaic Life Cycles, *Environmental Science Technology, 2008, 42(6).*

Gawal, E., Strunz, S., Lehmann, P. (2014), A public choice view on the climate and energy mix in the EU – How do the emissions trading scheme and support for renewable energies interact? *Energy Policy 64 (2014)* 175-182.

Ghosh, P. (2014), *Researchers develop cheaper way of making solar cells*, BBC NEWS Science and Environment. Accessed July 2014 from www.bbc.com/news/science-environment 28041220

Goulder, L, H, Hafstead, M, A, C, Dworsky, M. (2010), Impacts of alternative emissions allowance allocation methods under a federal cap-and-trade program, *Journal of Environmental Economics and Management 60 (2010)* 161-181.

Graham, R., George, A., Pennay. J. (2013), Discussions with environmental market specialists Bob Graham, SKMMMA, Andrew George, consultant for electricity generators, and James Pennay, wind farm specialist, during September and October 2013.

Grau, T. (2014), Responsive feed-in tariff adjustment to dynamic technology development, *Energy Economics, 44 (2014)* 36-46.

Green Energy Markets. (2014a), *Small-scale technology certificates. Data modelling for 2014 to 2016*. Report to the Clean Energy Regulator. January 2014. Accessed July 2014 from www.greenmarkets.com.au

Green Energy Markets. (2014b), *Small-scale technology certificates. Data modelling for 2015 to 2017*. Report to the Clean Energy Regulator. December 2014. Accessed October 2015 from www.greenmarkets.com.au

Grubb, M. (2012), Cap and Trade Finds New Energy, *Nature Vol 491*, 666-667.

Gurkan, G., Langestraat, R. (2014), Modeling and analysis of renewable energy obligations and technology bandings in the UK electricity market, *Energy Policy 70 (2014)* 85-95.

He, Y., Wang, L., Wang, J. (2012), Cap-and-trade vs carbon taxes: A quantitative comparison from a generation expansion planning perspective, *Computers and Industrial Engineering 63 (2012)* 708-716.

Heath, J. (2014), *$7.6 billion-a-year budget cost to chop carbon tax*, article in Australian Financial Review, 15 February 2014.

Heymans, C., Walker, S. B., Young, S. B., Fowler, M. (2014), Economic analysis of second use electric vehicle batteries for residential energy storage and load-levelling, *Energy Policy 71 (2014)* 22-30.

Holdermann, C., Kissel, J., Beigei, J. (2014), Distributed photovoltaic generation in Brazil: An economic viability analysis of small-scale photovoltaic systems in the residential and commercial sectors, *Energy Policy 67*, 612-617.

Honghang, S., Qiang, Z., Yanxi, L., Yurui, Z., Jun, S. (2014a), China's solar photovoltaic policy: An analysis based on policy instruments, *Applied Energy 129 (2014)* 308-319.

Honghang, S., Qiang, Z., Yibo, W., Qiang, T., Jun, S. (2014b), China's solar photovoltaic industry development: The status quo, problems and approaches, *Applied Energy 118, (2014)* 221-230.

Houser, T., Bradley, R., Staley, B.C., Werksman, J., and Heilmayr, R. (2008), *Leveling the Carbon Trading Field: International Competition and U.S. Climate Change Policy Design* Peterson Institute for International Economics. Accessed December 2014 from www.wri.org

Hu, X., Murgovski, N., Johannesson, L. M., Egardt, B. (2014), Comparison of three electrochemical energy buffers applied to a hybrid bus powertrain with simultaneous optimal sizing and energy management, intelligent Transportation systems, *IEEE Transactions on Intelligent Transportation Systems,, Vol 15 Issue 3* 1193-1205.

Hunt, G. (2013), (then) Opposition Spokesman on Climate Change, Lateline program on ABC Australian television, 18 April 2013.

Hsu, C. (2012), Using a system dynamics model to assess the effects of capital subsidies and feed-in tariffs on solar PV installations, *Applied Energy 100 (2012)* 206-217.

IEA. (2012), Renewable Energy Coming of Age, *The Journal of International Energy Agency, Issue 2, Spring 2012.* Accessed June 2014 from www.iea.org

IEA. (2014a), *Energy technology perspectives 2014 – harnessing electricity's potential*, International Energy Agency. Accessed January 2015 from www.iea.org/etp

IEA. (2014b), *Medium-Term Reports (Coal, Gas, Oil, Renewables and Energy Efficiency),* International Energy Agency. Accessed April 2015 from www.iea.org/publications

IEA. (2015), Renewable Energy Medium-Term Market Report 2015, Market Analysis and Forecasts to 2020, International Energy Agency. Accessed October 2016 from www.IEA.org

IEA. (2016), *Trends 2016 in Photovoltaic Applications. Survey Report of Selected IEA Countries between 1992 and 2015*. International Energy Agency. Accessed October 2016 from www.iea-pvps.org

IES. (2007), Intelligent Energy Systems. *Modelling the Price of Renewable Energy Certificates under the Mandatory Renewable Energy Target, An Update*. A Report to the Office of the renewable Energy Regulator Final, August 2007.

IRENA. (2015), *Renewable Power Generation Costs in 2014*. January 2015. International Renewable Energy Agency. Accessed April 2015 from www.irena.org

IRENA. (2016), *Renewable Energy Benefits: Measuring the Economics.* International Renewable Energy Agency. Accessed October 2016 from www.irena.org/DocumentDownloads/Publications

Jakob, M. (2012), The Fair Cost of Renewable Energy, *Nature Climate Change 2*, 488-489.

Jaffe, J., Ranson, M., Stavins, R. (2009), Linkable Trading Permit Systems: A key Element of Emerging International Climate Policy Architecture, *Ecology Law Quarterly Nov 2009 vol 36, Issue 4*, 789-807.

Jenner, S., Groba, F., Indvik, J. (2013), Assessing the strength and effectiveness of renewable electricity feed-in tariffs in European Union countries, *Energy Policy 52 (2013)* 385-401.

Jones, D. B. (2010), Proposal for an international carbon fee, *Energy for Sustainable Development 14 (2010)* 245-250.

Judson, J., M., Ranson R., Stavins, F., N. (2009). Linking Tradable Permit Systems: A Key Element of Emerging International Climate Policy Architecture, *Ecology Law Quarterly 36 2009* 789-808.

Kalkull, M., Edenhofer, O., Lessmann K. (2013), Renewable Energy Subsidies: Second-best Policy or Fatal Aberration for Mitigation? *Resource and Energy Economics, vol 35, issue 3, Sep 2013*, 217-234.

Khalilpour, R., Vassallo, A. (2016), Planning and operation scheduling of PV-battery systems: A novel methodology, *Renewable and Sustainable energy Reviews 53 (2016)* 194-208.

Kirsebom-Aronsen, C. (2013), *Political risk and international investment: the renewable energy market in Australia and the 2013 election,* Masters thesis, Norwegian Business School. Accessed May 2014 from www.brage.bibsys.no/bi

Komiyama, R., Fujii, Y. (2014), Assessment of massive integration of photovoltaic system considering rechargeable battery in Japan with high time-resolution optimal power generation model, *Energy Policy 66*, 73-89.

KPMG. (2014a), *Taxes and Incentives for Renewable Energy*, KPMG International. Accessed December 2014 from www.kpmg.com/energytax

KPMG. (2014b), *The Emissions Reduction Fund. How it will work and the key implications for business*. 28 April 2014. Accessed September 2014 from www.kpmg.com/au/en/Issues and Insights

Lavin, F., Dale, L., Hanneman, M., and Moezzi, M. (2011), "The Impact of Price on Residential Demand for Electricity and Natural Gas", *Climate Change*, *Vol 109 (2011*), 171-189.

Lazarowicz, M. (2009), *Global Carbon Trading: A Framework for Reducing Emissions*, Norwich, England: TSO Ireland. Accessed October 2014 from www.tsoshop.co.uk

Leepa, C., Unfried, M. (2013), Effects of a cut-off in tariffs on photovoltaic capacity: Evidence from Germany, *Energy Policy 56 (2013)* 536-542.

Lehmann, P., Gawal, E. (2013), Why should support schemes for renewable electricity complement the EU emissions trading scheme? *Energy Policy 52 (2013)* 597-607.

Lesser, J., Su, X. (2008), Design of an economically efficient feed-in tariff structure for renewable energy development, *Energy Policy 36 (3)* 981-990.

Li, Z., Boyle, F., Reynolds, A. (2011), Domestic application of solar PV systems in Ireland: The reality of their economic viability, *Energy 36 (2011)* 5865-5876.

Lilley, W.E., Reedman, L.J., Wagner, L. D., Alie, C. F., Szatow, A. R. (2012), An economic evaluation of the potential for distributed energy in Australia, *Energy Policy 51 (2012)* 277-289.

Liu, B., He, P., Zhang, B., Bi, J. (2012), Impacts of alternative allowance allocation methods under a cap-and-trade program in power sector, *Energy Policy 47 (2012)* 405-415.

Lo, A. (2012), Carbon Emissions Trading in China, *Nature Climate Change*, *Nov 2012*, *Vol 2.*

Lo, A. (2013), *How will China's carbon markets work in a non-market economy?*, The Conversation, 27 November 2013. Accessed July 2015 from www.theconversation.com

Lu, l., Yang, H. X. (2010), Environmental payback time analysis of a roof-mounted building-integrated photovoltaic (BIPV) system in Hong Kong, *Applied Energy 87 (2010)* 3625-3631.

Luta, A. (2014), *The Current State of the EU ETS*, presentation by Alexandru Luta, 22 July 2014. Accessed November 2015 from www.carbonmarketwatch.org/wp

McKibbin, W., Morris, A., Wilcoxen, P. (2014), A proposal to integrate price mechanisms into international climate negotiations, *Asia and the Pacific Policy Studies, Vol 1 no. 3* 600 – 608.

McKinsey & Company. (2008), *An Australian Cost Curve for Greenhouse gas Reduction*, February 2008. Accessed October 2013 from www.mckinsey.com

McKinsey & Company. (2009), *Pathways to a Low-carbon Economy: version 2 of the global greenhouse abatement cost curve*. Accessed October 2013 from www.mckinsey.com

McKinsey & Company. (2010), *Impact of the Financial Crisis on Carbon Economics - Version 2.1 of the global Greenhouse Gas Abatement Cost Curve.* Accessed September 2013 from www.mckinsey.com

McKinsey. (2012), *Solar Power: Darkest Before Dawn, McKinsey on Sustainability and Resource Productivity*, May 2012. Accessed January 2014 from www.mckinsey.com

Ma, C., Polyakov, M., Pandit, R. (2015), Capitalisation of residential solar photovoltaic systems in Western Australia, *The Australian Journal of Agricultural and Resource Economics*, *59*, 1-20.

MacGill, I., Outhred, H., Nolles, K. (2006), Some design lessons from market-based greenhouse gas regulation in the restructured Australian electricity industry, *Energy Policy 34 (2006)* 11-25.

Marshinski, R. Flicksland, C., Jakob, M. (2012), Sectoral Linking of Carbon Markets: A Trade Theory Analysis, *Resource and Energy Economics vol 34, issue 4, Nov 2012* 413-430.

Martin, N., Rice, J. (2013), The solar photovoltaic feed-in tariff scheme in New South Wales, Australia, *Energy Policy 61 (2013)* 697-706.

Mason, I. G., Page, S. C., Williamson, A. G. (2013), Security of supply, energy spillage control and peaking options within a 100% renewable electricity system for New Zealand, *Energy Policy 60 (2013)* 324-333.

Mayr, J., Schmidt, J., Schmid, E. (2014), The potentials of a reverse auction in allocating subsidies for cost-effective roof-top photovoltaic system deployment, *Energy Policy 69* 555-565.

Mananteau, P., Finon, D., Lamy, M-L. (2003), Price versus quantities: choosing policies for promoting the development of renewable energy, *Energy Policy (2003)* 799-812.

Meran, G., Wittman, N. (2012), Green, Brown and White Certificates: Are Three One Too many? A Micro-model of Market Integration, *Environmental and Resource Economics*, *53* 507- 532.

Mercari. (2015), Web site containing latest LGC prices. Accessed on a regular basis from www.mercari.com.au

MFE. (2010), *How will free allocation of emission units to the Industrial Sector work Now?*, Questions and Answers About Amendments to the New Zealand Emissions Trading Scheme, Ministry for the Environment, N.Z. Government. Accessed February 2014 from www.climatechange.govt.nz/emissions-trading-scheme

Millis, A. (2016), Discussions with Alan Millis, former Deputy Director, Department of Energy and Water Supply, Brisbane in February 2016.

Milstein, I., Tishler, A. (2011), Intermittently renewable energy, optimal capacity mix and prices in a deregulated market, *Energy Policy 39* 3922-3927.

Molyneaux, L., Froome, C., Wagner, L., Foster, J. (2013), Australian power: can renewable technologies change the dominant industry view? *Renewable Energy 60 (2013)* 215-221.

Muhammad-Sukki, F., Abu-Bakar, S. H., Munir, A. B., Yasin, S. H. M., Ramirez-Iniguez, R., McMeekin, S. G., Stewart, B. G., Sarmah, N., Mallick, T. K., Rahim, R. A., Karim, M. E., Ahmad, S., Tahar, R. M. (2014), Feed-in tariff for solar photovoltaic: The rise of Japan, *Renewable Energy 68 (2014)* 636-643.

Mundo-Hernandez, J., de Celis, B., Hernandez-Alvarez, J., de Celis-Carrillo, B. (2014), An overview of solar photovoltaic energy in Mexico and Germany, *Renewable and Sustainable Energy Reviews 31 (2014)* 639-649.

Narayan, P., K. Smyth, R. (2005), The Residential Demand for Electricity in Australia: An Application of the Bounds Testing Approach to Cointegration, *Energy Policy*, 33(4) 467–474.

Naumann, M., Karl, C, R., Truong C. N., Jossen, A., Hesse, H. C. (2015) Lithium-ion battery cost analysis in PV-household application, *Energy Procedia 73 (2015)* 37-47.

Nelson, T., Simshauser, P., Kelley. (2011), Australian Residential Solar Feed-in Tariffs: Industry Stimulus or Regressive form of Taxation?, *Economic Analysis and Policy*, *Vol 41*, *no. 2*, Sept. 2011.

NSW Government. (2011), *Small-scale solar PV generators*, NSW Government Trade and Investment FACTSHEET, 23 September 2011. Accessed May 2014 from www.resourcesandenergy.nsw,gov.au/factsheet-small-scale-renewables

O'Flaherty, F., Pinder, J., Jackson, C. (2012), *Determination of payback periods for photovoltaic systems in domestic properties*. Accessed December 2014 from www.shura.shu.ac.uk/5667

Oikonomou, V., Flamos, A., Spyridaki, N-A., Van der Gaast, W., De Domonicis, A., and Chung, N. (2012), "White Certificates and Domestic Offset Schemes: Possible Synergies", *Mitigation and Adaption Strategies for Global Change*, *Feb 2012 Vol 17, Issue 2*, 187–205.

Oliva, S. J., MacGill, I. J. (2011), *Dynamic Model Approach to Assess Feed-in Tariffs for Residential PV Systems*, University of New South Wales. Accessed October 2016 from www.ceem.unsw.edu.au/default/files/documents

Oliva, S. J., MacGill, I. J. (2012), *Assessing the Impact of Household PV Systems on the Profits of All Electricity Industry Participants*, University of New South Wales. Accessed October 2016 from www.ceem.unsw.edu.au/default/files/documents

Oliva, S., MacGill, I. (2013), *Dynamic Model Approach to Assess Feed-in Tariffs for Residential PV Systems*. Paper presented to International Association of Energy Economics (IAEE) Conference, Daegu, Korea 16-20 June 2013. Accessed October 2016 from www.ceem.unsw.edu.au/sites/default/files/documents

Orioli, A., Di Gangi, A. (2014), Review of the energy and economic parameters involved in the effectiveness of grid-connected PV systems installed in multi-storey buildings, *Applied Energy 113 (2014)* 955-969.

Orszag, P. R. (2008), *Issues in Designing a Cap-and-Trade Program for Carbon Dioxide Emissions*, Testimony to Committee on Ways and Means, U.S. House of Representatives, 18 September 2008, by Peter R. Orzag, Director, Congressional Budget Office.

Ouyang, X., Lin, B. (2014), Levelized cost of electricity (LCOE) of renewable energies and required subsidies in China, *Energy Policy 70 (2014)* 64-73.

Parkinson, G. (2013), *People power: Rooftop solar PV reaches 3GW in Australia*. Accessed May 2014 from www.reneweconomy.com.au

Parkinson, G. (2015), *Tesla already forcing down battery storage prices in Australia*. Accessed October 2015 from www.reneweconomy.com.au

Parliament of Australia. (2009), *Bills Digest*, Parliament of Australia, Department of Parliamentary Services, 24 June 2009. Accessed June 2015 from www.aph.gov.au/library

Parliament of Australia, (2011), *Feed-in-tariffs*. Accessed December 2013 from www.aph.gov.au/About_Parliament/Parliamentary_Departments

Parra, D., Gillott, M., Norman, S. A., Walker, G. S. (2015), Optimum community energy storage system for PV energy-time shift, *Applied Energy 137 (2015)* 576-587

Perez, R., Burtis, L., Hoff, T., Swanson, S., Herig. (2004), Quantifying residential PV economics in the US – payback vs cash flow determination of fair energy value, *Solar Energy 77 (2004)* 363-366.

PIN. (2013), *Pump Storage Debate*, Power Industry News article, 14 October 2013, on Arup and University of Melbourne Energy Institute examining seawater pump storage, Subscription publication, Editor Bruce Bertram.

Plante, R., H. (2014), *A Technical and Economic Guide for Project Planners, Builders and Project Owners*. Chapter 8: The Economics of Solar Photovoltaic Systems. Solar Energy, Photovoltaics, and Domestic Hot Water, 1st Edition, 8 May 2014, Academic Press.

Queensland Competition Authority. (2013), *Regulated Retail Electricity Prices 2013-14, Final Determination*. Queensland Competition Authority. Accessed May 2014 from www.qca.org.au

RAA. (2104), *Solar Facts. Facts about Solar and the Small-scale Renewable Energy Scheme*. Rec Agents association. Accessed May 2014 from www.recagents.asn.au/solar-facts

REN21. (2016), *Renewables 2016 Global Status Report*, Accessed October 2016 from www.ren21.net/up-content/uploads/2016

Reichelstein, S., Yorston, M. (2013), The prospects for cost competitive solar PV power, *Energy Policy 55 (2013)* 117-127.

Repetto, R. (2013), *Cap and Trade is Better Climate Policy than a Carbon Tax*, United Nations Foundation May 2013. Accessed January 2015 from www.energyfuturecoalition.org

Reuter, W. H., Szolgayova, J., Fuss, S., Obersteiner, M. (2012), Renewable energy investment: policy and market impacts, *Applied Energy 97 (2012)* 249–254.

Richstein, J. C., Chappin, E. J. L., de Vries, L. J. (2015), Adjusting the CO_2 cap to subsidised RES generation: Can CO_2 prices be decoupled from renewable policy? *Applied Energy 156 (2015)* 693-702.

Rickerson, W., Hanley, C., Laurent, C., Greacen, C. (2013), Implementing a global feed-in tariff in developing countries: A case study of Tanzania, *Renewable Energy 49 (2013)* 29-32.

Rigter, J., Vidican, G. (2010), Cost and optimal feed-in tariff for small-scale photovoltaic systems in China, *Energy Policy 38 (11)* 6989-7000.

Ringel, M. (2006), Fostering the use of renewable energies in the European Union: the race between feed-in tariffs and green certificates, *Renewable Energy 31 (2006)* 1-7.

Rio, d. P., Herenandez, F., Gual, M. (2005), The Implications of the Kyoto project mechanisms for the deployment of renewable electricity in Europe", *Energy Policy, 33 (2005)* 2010 – 2022.

ROAM Consulting. (2012), *Impact of Renewable Energy and Carbon Pricing Policies on Retail Electricity Prices (update)*, Report to the Australian Clean Energy Council, 10 May 2012.

Rocky Mountain Institute. (2014), *The economics of grid defection: when and where distributed solar generation plus storage competes with traditional utility service*. Accessed January 2014 from www.rmi.org

Roelfsema, M., Elzen, d. M., Hohne, N., Hof, A. F., Braun. N., Fekeyte, H., Bottcher, H., Brandsma, R., Larkin, J. (2014), Are major economies on track to achieve their pledges for 2010? An assessment of domestic climate and energy policies, *Energy Policy 67 (2014)* 781-796.

Rose, I. (2015), Discussions with Ian Rose, senior consultant, Ernst and Young, Brisbane in December 2015.

Sabbaghi, O., Sabbaghi, D. (2011), Carbon Financial Instruments, Thin Trading, and Volatility: Evidence from the Chicago Climate Exchange, *The Quarterly Review of Economics and Finance, Vol 51, Issue 4, November 2011*, 399-407.

Saddler, H. (2007), *Potential Electricity System Demand Reductions from Distributed Measures: Residential and Commercial/Services Sectors*, Energy Strategies, 18 May 2007. Accessed October 2016 from www.climateinstitute.org.au/verve/resources/potentialsystemdemand.pdf

Saddler, H. (2014), *Why is electricity consumption decreasing in Australia?* The Conservation 2 January 2014. Accessed October 2016 from www.reneweconomy.com.au/why-is-electricity-consumption-decreasing-in-Australia-19459

Schleicher-Tappeser, R. (2012), How renewables will change electricity markets in the next five years, *Energy Policy 48*, 64-75.

Schmalansee, R. (2012), Evaluating policies to increase electricity generation from renewable energy, *Review of Environmental Economics and Policy, 6 (1) (2012)* 45-64.

Sevilgen, S., Erdem, H., Cetin, B., Akkaya, A., and Dagdas, A. (2004), Effect of economic parameters on power generation expansion planning, *Energy Conversion and Management* Vol *46 (2005)* 1780-1789. Accessed January 2015 from www.sciencedirect.com

Shahiduzzam, M., Layton, A., Alam, K. (2015), Decomposition of energy-related CO_2 emissions in Australia: Challenges and policy implications, *Economic Analysis and Policy 45 (2015)* 100-111.

ShahNazari, M., McHugh, A., Maybee, B., Whale, J. (2014), Effect of political cycles on power investment decisions: expectations over the repeal and reinstatement of carbon policy mechanisms in Australia, *Applied Energy 130 (2014)* 157-165.

Simshauser, P. (2011), The Hidden Costs of Wind Generation in a Thermal Power System: What Cost? *The Australian Economic Review, vol 44, no. 3*, 259-92.

Simshauser, P. (2014), *Energy Industry – Challenges Ahead*, presentation to International Energy Centre, 19 May 2014, Brisbane, Australia.

Simshauser, P., Docwra, G. (2004), Reducing Greenhouse Gas Emissions in the Queensland Electricity Supply Industry: Gas and Carbon Tax Scenarios, *The Australian Economic Review, vol 37, no. 3*, 287-303.

Skoufa, L., Tamaschke, R. (2011), Carbon prices, institutions, technology and electricity generation firms in two Australian states, *Energy Policy 39 (2011)* 3606-2614.

SKMMMA. (2011), *Carbon Pricing and Australia's Electricity Markets*, July 2011 and updated on September 2011, SKMMMA for The Treasury. Accessed December 2014 from www.treasury.gov.au

Spath, P.L. (2004), *Biomass power and Conventional Fossil Systems with and without CO2 sequestration – comparing the energy balance, greenhouse gas emissions and economics*, report No BB04.4010. National Renewable Energy Laboratory, 2004. Accessed in March 2015 from www.bioenergykdf.net/node/129

Speidel, S., Braunl, T. (2016), Leaving the grid-The effect of combining home energy storage with renewable energy generation, *Renewable and sustainable Energy Reviews 60 (2016)* 1213-1224

Spiecker, S., Weber, C. (2014). The future of the European electricity system and the impact of fluctuating renewable energy – A scenario analysis, *Energy Policy 65*, 185-197.

Stenzel, P., Linssen, J., Fleer, J. (2015), Impact of Different Load Profiles on Cost Optimal System Designs for Battery Supported PV Systems, *Energy Procedia 75 (2015)* 1862-1868.

Sun, P., Nie, P. (2015), A comparative study of feed-in tariffs and renewable portfolio standard policy in renewable energy industry, *Renewable Energy Vol. 74 February 2015* 255-262.

Sun, C., Ouyang, X. (2016), Price and expenditure elasticities of residential energy demand during urbanization: An empirical analysis based on the household-level survey data in China, *Energy Policy 88 (2016)* 56-63.

SunWiz. (2012), *Solar PV Forecast for AEMO 2012-2022* - Considerations for the Energy Market Operator, SunWiz Consulting and Solar Business Services. Accessed in March 2014 from www.sunwiz.com.au

SunWiz. (2013), *Special Announcement: Australia Reaches 3 GW of PV*. Accessed June 2014 from http://ww.sunwiz.com.au/index.php/2012-06-26-00-47-40/269-3gw-ofaustralian-pv.html).

Sutherland, L-E., Holstead, K. (2013),"Future-Proofing the Farm: On-Farm Wind Turbine Development in Farm Business decision-making", *Land Use Policy, Volume 36, January 2014*, 102-112.

Sydney Morning Herald. (2011), *Solar Industry Welcomes NSW backdown*, Sydney Morning Herald, 7 June 2011.

Syed, A. (2012), *Australian Energy Projections to 2049-50*, Australian Government Bureau of Resources and Energy Economics, December 2012. Accessed May 2014 from www.bree.gov.au

Taha, A.F., Hachem, A. N., Panchal, J. H. (2014), A quasi-feed-in-tariff policy formulation in micro-grids: A bi-level multi-period approach, *Energy Policy 71 (August 2014)* 63-75.

Talavera, D. L., Nofuentes, G., Aguilera, J. (2010), The internal rate of return of photovoltaic grid-connected systems: A comprehensive sensitivity analysis, *Renewable Energy 35 (2010)* 101-111.

Talberg, A., and Swoboda, K. (2013), *Emissions trading schemes around the world*, Background Note. Parliamentary Library, Parliament of Australia, Department of Parliamentary Services. Accessed August 2014 from www.aph.gov.au

Tamas, M., M., Bade Shrestha, S., O., Zhou, H. (2010), Feed-in tariff and tradeable green Certificate in oligopoly, *Energy Policy 38(8) (2010)* 4040-4047.

Trancik, J. (2014), Renewable energy: Back the renewables boom, *Nature Vol 507, number 7492*, 300-302.

Treasury. (2011a), *Strong Growth, Low Pollution Modelling a Carbon Price*, July 2011, Australian Government, The Treasury. Accessed August 2014 from www.treasury.gov.au

Treasury. (2011b), *Carbon Pricing and Australia's Electricity Markets*, July 2011, SKM MMA. Accessed Marh 2014 from www.archive.treasury.gov.au

Tsantopoulos, G., Arabatzis, G., Tampakis, S. (2014), Public attitudes photovoltaic developments: Case study from Greece, *Energy policy 71 (2014)* 94-106.

United Nations. (1998), *Kyoto Protocol to the United Nations Framework on Climate Change,* (UNFCCC). Accessed August 2014 from www.unfccc.int/kyoto_protocol

UNEP. (2014), *The Emissions Gap Report*. United Nations Environment Programme (UNEP), Nairobi. Accessed November 2015 from www.unep.org/emissionsgapreport2014

Uran, V., Krajcar, S. (2013), A methodology for analysis of the renewable electricity feed-in tariff markets, *Electrical Power and energy Systems 53 (2013)* 1-9.

Valenzuela, J., Thimmapuram, R., Kim, J. (2012), Modelling and simulation of consumer response to dynamic pricing with enabled technologies, *Applied Energy 96 (2012)* 122-132.

Vob, J-P. (2007), Innovation Processes in Governance: The development of "emissions trading" as a new policy instrument, *Science and Public Policy Vol 34(5)* 329-343.

Vorrath, S. (2015), *UBS: Battery storage payback for solar households will be 5-6 years by 2020*, Accessed October 2015 from www.onestepoffthegrid.com.au/author/sophie-vorrath

Wagner, L., Foster, J. (2011), Is There an Optimal Entry Time for Carbon Capture and Storage? A Case Study for Australia's National Electricity Market, *Journal of Economic Literature* Q40; G12:C61.

Wagner, L., Froome, C., and Foster, J. (2010), *Modelling the Broader Deployment of Demand Side Management onto the Australian National Electricity Market*, University of Queensland presentation, 2010.

Wang, Q., Zhang, C., Ding, Y., Xydis, G., Wang, J., Ostergaard, J. (2015), Review of real-time electricity markets for integrating Distributed Energy Resources and Demand Response *Applied Energy 138 (2015*) 695-706.

Watt, M., Passey, R., Johnston, W. (2012), *PV in Australia 2011*. Prepared for the international Energy Agency Cooperative Programme on PV power systems by Australian PV Association may 2012. Accessed June 2014 from www.apva.org.au

Weisser, D., Strasse W. (2007), A Guide to Life Cycle Greenhouse gas (GHG) Emissions from electricity Supply Technologies, *The Journal of the International Energy Agency, Vol 32 (2007)* 1543-1559.

Westpac Banking Corporation. (2012), *Clean Energy Future Update*, presentation to Invited Brisbane corporates in February 2012.

Wilkie, O., MacGill, I., Bruce, A. (2015), *Revenue Sufficiency in the Australian Electricity Market with High Penetrations of Renewable Energy*, Presentation to 2015 Asia-Pacific Solar Research Conference. Accessed October 2016 from www.apvi.org.au/solar-research-conference

Wilkins, R. (2008), *Strategic Review of Australian Government Climate Change Programs, 31 July 2008*. Known as "Wilkins Review". Accessed October 2016 from www.finance.gov.au/publications

Williamson, M. (2016). GM Wholesale Markets, Ergon Energy Corporation Limited. Comments arising from discussions with Mark Williamson on 21 March 2016.

Woerdman, E. (2000), Implementing the Kyoto protocol: why JI and CDM show more promise than international emissions trading, *Energy Policy 28 (2000)* 29-38.

Wood, P. J., Jotxo, F. (2011), Price floors for emissions trading, *Energy Policy 39 (2011)* 1746-1753.

World Bank. (2014), *Media Teleconference on Carbon Pricing with World Bank President Jim Yong Kim and Vice President and Special Envoy for Climate Change Rachel Kyte*, 22 September 2014. Accessed October 2014 from www.worldbank.org/en/news/speech/2014/9/22.

World Bank Group. (2014), *State and Trends of Carbon Pricing*. World Bank Group, Climate Change. Washington, D C. May 2014. Accessed September 2014 from www.worldbank.org

Wurzburg, K., Labandeira, X., Linares P. (2013), Renewable generation and electricity prices: Taking stock and new evidence for Germany and Austria, *Energy Economics 40*, 159-171.

Xiaosong, Hu., Murgovski, N., Johannesson, L. M., Egardt, B. (2014), Comparison of here electrochemical energy buffers applied to a hybrid bus powertrain with simultaneous optimal sizing and energy management, intelligent Transportation systems, *IEEE Transactions on, Vol 15 Issue 3* 1193-1205.

Yang, Z., Zhang, J., Kintner-Meyer, M. C. W., Lu, X., Choi, D., Lemmon, J. P., Liu, J. (2011), Electrochemical energy storage for green grid, *Chemical Reviews 2011, 111(5),* 3577-3613.

Young, S., Hungerford, Z., MacGill, I., Bruce, A. (2015), *Impacts of Electric Vehicles on Australian National Market and Household Expenditure under Different Charging Regimes,* Presentation to 2015 Asia-Pacific Solar Research Conference. Accessed October 2016 from www.apvi.org.au/solar-research-conference

Yuan, C., Liu, S., Yang, Y., Chen, D., Fang, Z., Shui, L. (2014), An analysis on investment policy effect of China's photovoltaic industry based on feedback model, *Applied Energy 135 (2014)* 423-428.

Zahedi, A. (2011), Maximising solar PV energy penetration using energy storage technology, *Renewable and Sustainable Energy Reviews 15 (2011)* 866-870.

Zheng, M., Meinrenken, C. J., Lackner, K. S. (2014), Agent-based model for electricity consumption and storage to evaluate economic viability of tariff arbitrage for residential sector demand response, *Applied Energy 126 (2014)* 297-306.

Zhou, Y., Wang, L., McCalley, J., D. (2011), Designing effective and efficient incentive policies for renewable energy in generation expansion planning, *Applied Energy 88 (6) June 2011* 2201-2209.

Appendix A: Model Explanation

This Appendix provides additional detail relating to the model that has been developed. It is in three parts: firstly explaining the process used in determining annual payback periods for household PV; secondly explaining how the components of retail prices and total generation by fuel type, emission levels and pool prices were determined; and thirdly explaining how total output and subsidy-related output were determined for each large-scale renewable energy type. The financial year ended June 2013 was used as a specific example in some instances.

Information from various publications was used to either provide the necessary data or provide closely related information to ensure approximations were as realistic as possible. Some of the information sources not shown in References, are listed at the end of this Appendix.

A.1 Household PV model explanation

PV at the household level was analysed, on an annual basis from 2005 to 2014 and then forecast to 2020, by noting the average size of new solar systems (which ranged from 2.5kW to 3.9 kW over time), the average cost of new solar panels, using $/MWh costs inclusive of installation costs, which was then discounted by the value of STCs. This information was used in the regression model to convert payback periods to forecast levels of household PV uptake and then compared with other household PV forecasts which were not dissimilar.

STC prices used ranged from low AU$30s/MWh to AU$39/MWh reflecting the legislative AU$40/MWh cap. For modelling purpose a future AU$37/MWh price was used. Benefits were noted as the value of electricity exported to the grid, calculated from the weighted average FIT in Australia in the years concerned and the volume of exports, plus reduced consumption benefits arising from solar output being used for domestic consumption. The weighted average FIT was determined on a state by state basis for each year. The volume of exports was developed by noting the average output of new PV systems, being 3.5 hours per day, then separated into output exported to the grid (2.5 hours per day) and output used to offset domestic consumption (1.0 hours per day). These figures were derived from Frontier Economics (2001) and also cross checked data from other sources such as AEMO (2000).

FIT revenue was noted as the payment made by retailers for electricity benefits they received from a reduction in their electricity purchases, in the order of AU6c/kWh to AU8c/kWh, plus the legislated FIT retailers received from network companies, being each state’s legislative obligation.

The cost and benefit figures were used to calculate annual payback periods. This method of financial evaluation is comparatively simple enabling households to easily determine the economics of their decision-making. The outcome was payback periods falling to a low of three to four years in 2010 and 2011, subsequently increasing to five to six years, supported by the continuation of relatively high electricity franchise tariffs.

Payback periods were regressed against the actual uptake of household PV, which was used for sensitivity analysis as mentioned in Section 5.6. Household PV output was used to determine numbers of STCs, noting the deeming impact, and factored up to produce annual numbers of STCs. The numbers compared favourably with those reported in EGA(2014). PV output exported to the grid and used to offset domestic consumption was examined to determine the level of GHG emission reductions on a counter-factual basis as discussed in Section 6.1.

A.2 Generation data and retail price build-up explanations

A model replicating generation by fuel type was developed covering the 20 year period 2000 to 2020. Input and output data were determined for each financial year with annual trends analysed as a reality cross check. FY 2013 was chosen as a sample year to explain key components in detail. Key components were:

Marginal cost of energy (MCE)

The marginal cost of energy associated with each of the four generation fuel types has three components being:

Carbon price

For FY 2013 there was a carbon price in place of AU$23/tonne of CO_2e. The contribution of this price in the pool price is a reflection of the types of generation setting the pool price. For example if only gas-fired generation was setting the pool price the contribution would be AU$13.8/MWh because gas-fired generation has a carbon intensity factor of 0.6 tonnes of CO_2e/MWh of output. For FY 2013 the mix of generation types setting the pool price is shown in the blue column headed "MP set" (Table A-1). The generation type mix was applied on a weighted average basis to the carbon intensity factor for each fuel type in the column headed "carbon int. fctr" giving rise to the AU$18.14/MWh carbon price component of the pool price.

Fuel price

The fuel price was highest for gas-fired generation, at AU$35/MWh, calculated from a gas price of AU$3/GJ and a heat rate (GJ/MWh) of 10. Brown and black coaled-fired generation were the next most expensive, between AU$18 and AU$20/MWh. Renewable energy has a very low marginal cost of energy as the inputs are wind, solar and hydro, with bagasse being the only renewable generation with a small fuel cost. .

Capital recovery cost

Capital recovery reflects the extent to which each generator type is able to recover its fixed costs, reflected in the level of competition at that time. This cost component is in effect the balancing component used to produce the total cost able to be recovered by each generation type in setting the pool price. It represents the difference between known pool prices and known input costs.

Calibration of cost components

The model was calibrated against various cost and market data as a reality check and to ensure consistency. For example the pool price is known (from AEMO) to be AU$59.58/MWh for FY 2013. Total output by generation type is provided by BREE (Bureau of Resource and Energy Economics). Knowledge of which generators set the pool price was obtained from ad hoc publications from organisations such as ROAM Consulting and by analysing AEMO pool price data by half-hour. As mentioned in Section 5.6.3, AEMO pool price data were analysed on a half-hour basis for calendar year 2012 as part of the household PV determination of emissions reductions. Hence it was possible to approximate the mix of generation types that set the pool price in FY 2013.

Retail electricity price

The retail electricity price, built up from AEMC and BREE data, has components:

Energy prices

Energy prices used were an average of pool prices in the current year and the previous year (that is AU$30.62/MWh for FY 2012 and AU$59.58/MWh for FY 2013, giving a figure of AU$79.85/MWh that was used). The reason for this is that the energy component is calculated differently in each state by that state's regulator, generally comprising a mix of the LRMC for new generation, and market contract prices. Market contract prices are usually at a margin above the previous year's pool price. Hence a mix of current and previous year energy prices was used as an approximation. This is not a critical component of the modelling.

Peak adjustment factor

A peak adjustment factor was applied to convert flat (time weighted) energy prices into profiled (load weighted) energy prices, being representative of the load profile of energy that retailers are required to purchase from AEMO. This reflects the fact that retailers are required to purchase more electricity in peak periods when pool prices are higher. A factor of 1.8 was used in earlier years declining to 1.4 for current and future years, reflecting action taken by consumers to reduce the peakiness of their loads, with household PV being largely responsible for this.

Network costs

Network costs were approximated from a range of sources, including tariff determinations by state regulators, and cross-checked with reported percentage breakdowns of retail price components as well as a trend series developed to track approved network costs each year. Network costs are also partly a balancing component between known retail prices and other substantiated cost component. FITs included in network charges were deducted for reporting separately as one of the renewable energy subsidies. Although approximations were required network costs are not a critical component of the analysis. Network costs were also expressed on a per MWh basis, using BREE total generation data.

Renewable energy costs

Renewable energy costs, exclusive of grants, comprise three components: STC costs; LGC costs; and FIT costs. STC and LGC costs were each calculated by multiplying the percentage liability obligation by STC and LGC prices. STC and LGC prices and FITs are covered in detail in Chapter 5. Unit costs were factored up to produce total Australian costs which were cross-checked against published data.

The remaining part of Table A.1 shows renewable and FIT figures expressed in different ways.

Table A-1 FY 2013 Screen shot of model components of retail electricity prices

R	2012/13								
Input Factors	Carbon price	pass thro %							
carbon cost	**23.00**	79%	18.14						
Other energy cost			41.44						
Total (pool price)			59.58					-	
	MCE	-	-	-	-	-	**MP set**	**Output**	**Emissions**
Fuel Type	**ie fuel**	**carbon int. fctr**	**carbon cost**	**Inc carbon**	**Cap Rec.**	**Total cost**	**wtg**	**(GWh pa)**	**(000 tCo2)**
brown coal	**20**	**1.3**	**30.8**	**50.8**	**13.0**	**63.8**	**18%**	**47,555**	63,724
black coal	**18**	**0.9**	**21.6**	**39.6**	**10.0**	**49.6**	**22%**	**10,050**	104,802
gas	**35**	**0.6**	**14.7**	**49.7**	**21.0**	**70.7**	**52%**	**57,463**	36,776
renewables	**1**	**0.1**	**2.3**	**3.3**	**0.0**	**3.3**	**8%**	**32,566**	3,257
Total		**0.84**			**115.3**	**wtd av.**	**59.58**	**147,634**	208,558
		wtd av.	carbon cost in pool price		18.14		**$/MWh**	253.8	
gas price ($/GJ)	**3**		cost ex. Carbon		41.30		59.58		
heat rate	**10**					Peak adj. fctr	1.80		
					107.24	Profiled cost	79.85		
				2.12	**Includes FIT**	Network cost	*160.00*		
		renewables % of ret. Price			4%	renewables	**$13.23**	STC Ratio	STC cost
	Carbon in retail price		32.66	$/MWh				**21.36%**	$34
	Carbon % of retail price		11%	carbon		retailer margin	43.02		40
						Retail elec. Price	**296.10**		

.

A.3 Explanation of how renewable energy model data was determined

The information shown in Tables 6.8 to 6.11, particularly annual output and subsidy-related output, was determined by ensuring the data was as close as the model would allow to BREE (now Office of Chief Economist) output data and the CER's Registry on creation of LGCs by renewable energy type.

For each renewable energy type the level of capacity, in MW, was determined from EGA (2010) and cross-checked against other information including Energy Supply Association of Australia annual reports. On a year by year basis for each renewable energy type, the level of capacity was converted to annual output by noting the average hours the renewable energy type was most likely to operate, factored up from average hours per day. The outcome was calibrated against actual (BREE) annual output. Specifically large-scale solar operated at between 5 and 9 hours per day, averaging 7 hours per day post 2016. Wind was found to operate between 6 and 9 hours a day, averaging 9 hours per day post 2016. Hydro was found to operate 4 to 6 hours per day, averaging 6 hours per day post 2016. Bagasse proved to be the most difficult to analyse because output reflected both good and bad sugar crush seasons and because output was seasonal. This was made easier when Pioneer (68 MW) came on stream in 2005 and MacKay Racecourse (38 MW) came on stream at the end of 2012, both being run almost all year round. Hence bagasse was found to operate initially between 6 and 8 hours a day, although lower in the poor crush seasons of 2001 and 2002, increasing to 12 hours a day post 2011 which was retained post 2016.

In each year, levels of additional capacity were determined, being input into determination of payback periods. Large-scale solar showed little new capacity until 2010 when subsidy-assisted Moree (56 MW), Kogan Creek Solar Boost (46 MW) and AGL's Nyngan (147 MW) projects took effect. With wind, additional and often substantial capacity increases occurred regularly, year by year, with the outcome showing a close correlation with annual wind output, being the closest of any renewable energy type. Hydro energy was also easy to analyse as very little additional capacity occurred since the base level of 8,000 MW in 1997. In the case of bagasse, as mentioned in the previous paragraph, capacity increases were on one-off bases, being subsidy driven, the first being Rocky Point (30 MW) in 2001.

Subsidies associated with capital increases were allocated over the years when additional capital was expected to take effect. This process enabled payback periods to exhibit meaningful results, such as no payback period being negative, for each renewable energy type.

Capital costs (AU$/MW) were noted from various sources including Renewable Power Generation Costs (2014) and press releases relating to individual projects, such as Ecogeneration (2009) stating, for example that Broadwater and Condong (total of 60 MW) cost AU$220 million, being AU$3.7/MW, in line with trend figures used.

Payback periods were then determined by using capital costs mentioned above, discounted by any grants, and revenue from LGCs and load weighted pool price exports to the grid less any fuel costs. Fuel costs were only applied in the case of bagasse as there are no fuel costs associated with the other types of renewable energy. Load weighted pool prices were used to reflect revenue that would be paid under Power Purchase Agreements, being the revenue stream that most projects would seek to secure.

Biomass was treated differently from other renewable energy types as it consists of nine different energy types, with REC Registry data showing most output from land fill gas, followed by black liquor, wood waste and waste coal mine gas. The approach taken was to use BREE data for output and to assume growth post 2016 in line with past growth rates with LGC creation being output levels less CER baseline levels.

A.4 Reconciliation of large-scale renewable energy output with REC Registry data

The Clean Energy Regulator (CER) maintains a Renewable Energy REC Registry which requires, by legislation, that creators of STCs and LGCs register these environmental certificates. The creators can then on-sell these certificates to parties such as electricity retailers, who have a legal obligation to purchase these certificates each calendar year.

The model that has been developed serves various purposes including determining output levels and numbers of LGC and STC levels, which are reconciled against public data including LGCs shown in the REC Registry, for each fuel type. The importance of this reconciliation is to ensure renewable subsidy levels (which LGCs and STCs represent) are accurately modelled for forecasting subsidy levels and forecasting the growth in renewable energy. It is the increase in numbers of STCs and LGCs, since 2020 that help determine whether Australia is able to meets its renewable energy targets.

The REC Registry contains STCs and LGCs by validity type, of which there are seven, six of which cover LGCs, and fuel type, of which there are 20. Fuel types have been aggregated into six categories: household PV, large scale PV, hydro, wind, bagasse and biomass.

The number of LGCs produced has been recreated in a model by noting total output, reconciled against BREE data, in the six categories mentioned from which baseline levels converted from calendar years to financial years, have been deducted.

The CER defines LGC baselines as the average of renewable energy output over the three years 1994, 1995 and 1996. However investigation of the REC Registry shows that in fact this is only an approximation (Table A-2) so actual baseline levels shown in the CER website (under Register of accredited power stations) have instead been used.

In broad terms it could have been expected that output levels less baseline levels determine the number of LGCs. This was not always the case, particularly in fuel types where there were many producers whose output varied above and below their baselines, such as with sugar cogeneration (cogen) mills. Where baselines were above output levels, increased output may not have produced LGCs if output did not reach this level. Furthermore in some years the output of some plants may go over baseline levels and for other plants drop below baseline levels. These comments are made to highlight the difficulties in reconciling (BREE) output above baselines with (REC Registry) actual LGCs created, being a particular issue with bagasse cogen and hydro energy. Reconciliation was made easier through discussions with the CER who advised that they did not consider LGCs “invalid due to audit” and “pending audit” to be creditable LGCs at this stage (CER, 2016). The fact that for bagasse and hydro, good years generally apply to the fuel type as a whole helps reduce this effect.

Baseline and output analysis by renewable energy fuel type

Hydro energy

The hydro energy baseline shown in the REC Registry averages 15,630 GWh pa which compares with BREE’s 16,200 GWh pa average hydro output over 1994, 1995 and 1996 in effect providing LGCs above the three year output averages. The number of LGCs shown in the REC Registry, when compared with BREE output numbers, on a common financial year basis, requires the REC baseline figure to be on average 1,600 GWh pa lower than the 15,630 GWh pa baseline figure. The figures have been examined in as much detail as is available, including individual hydro power station baselines but LGCs are only available in aggregate for all hydro power stations. Only parties that are participants, that is inputting data into the REC Registry, can view individual power station LGC figures. Similarly BREE data is only available for hydro power stations in aggregate. Discussions with the CER personnel have not assisted in trying to resolve why baselines used are effectively lower than indicated, being necessary to generate these higher than anticipated LGC numbers. This apparent hydro baseline reduction was also noted by MacGill et al (2006).

To ensure a meaningful relationship could be established between hydro output levels and LGCs created, baselines were reduced by an average 1,600 GWh pa with variations summing to zero on an annual basis.

Wind energy

Modelling of renewable energy growth and associated LGC data were found to be very close for wind energy, assisted by there being a very small baseline and hence not complicated by variations in baseline levels.

Solar Energy

Solar energy was split into three sections: household PV generating STCs, large scale solar generating LGCs and non-subsidised, possibly commercial, solar operating prior to 2000 which because of the timing, did not generate either STCs or LGCs. BREE data is the basis for non-subsidised solar energy.

The total solar output position, as determined by BREE, was taken as the starting point. Household PV, as determined by the detailed model, was deducted from these figures on an annual basis to provide non-household PV, consisting of large-scale LGC stimulated solar and non-subsidised solar.

Large-scale solar output was determined from the number of solar LGCs, that is excluding small-scale solar STC, shown in the REC Registry which will be an accurate indicator as there is no solar baseline. Non-subsidised solar therefore became the residual figure.

For forecasting purposes it was assumed the historic growth in non-subsidised solar would continue, resulting in non-subsidised solar decreasing from 100% of all solar output in 2000 to below 10 percent from FY 2012 onwards. Consistency with BREE output data was maintained.

Bagasse

For bagasse BREE data was matched against output from sugar cane co-gen plants.

The REC Registry shows that the LGC baseline increased only marginally, from 468,000 LGCs in 2002 to 510,000 LGCs in 2003, rising to 513,000 where it has remained since FY 2008.

Output was very low in the drought years of 2000 and 2001 but has since risen substantially from 291,000 MWh in FY 2002, the first full year, to 1,676,000 MWh in FY 2015. The increase in LGCs has however not matched output growth increasing from 278,000 LGCs in FY2002 to 822,000 LGCs in 2015, an increase of 544,000 LGCs compared with output increase of nearly 1,400,000 MWh. Part of the reason is because increased output has occurred with some mills that had yet to reach baseline levels and therefore did not produce LGCs in line with increased output.

Biomass

It was not possible to model inputs and outputs for biomass, being from a wide range of fuels but biomass needed to be included as it is a material figure contained in BREE data. However it was possible to apply a similar concept to that used for other renewable fuels, that is average output over the three base years of 1994, 1995 and 1996 was determined and deducted from output post

2000 to determine growth volumes that would generate LGCs. A continuation of average annual growth of 5 percent pa was used to develop forecasts over the period FY2015 to FY 2020. The same emission reduction effects were assumed to apply as for bagassse generation.

Variations in renewable energy baselines

Variations in renewable energy baselines were found to occur between those determined from the average output for years 1994, 1995 and 1996, as required by legislation, and actual baselines notified by the CER. This is likely to be mainly due to the average output figures provided by Australian Government, Department of Industry and Science. (2015a) being on a financial year basis and the CER figures being on a calendar year basis, but converted to financial year figures. For modelling purposes, to ensure LGCs created lined up with those in the REC Registry, baselines used more closely aligned with the CER figures (Table A-2).

Table 2-2 Comparison of financial year renewable energy baselines

Fuel type	Average 1994, 1995, 1996 output	Shown in REC Registry (2002)	Used in Modelling (FY 2002)
	(GWh)	(GWh	(GWh)
Large-scale solar	19	0	0
Wind	4	5	6
Hydro	16,206	15,673	15,130
Bagasse	104	467	308
Biomass	670	574	560
Total	17,003	16,719	16,004

Source: Australian Government, Department of Industry and Science. (2015a), REC Registry in Clean Energy Regulator website (www.cleanenergyregulator.gov.au),

A.5 Sources of information used to provide model data not elsewhere specified

The following data reference sources were used in the model being in addition to data reference sources mentioned in the main document.

ABARES. (2011). “Energy in Australia” (www.abares.gov.au) for 2011 renewable energy data

AER. (2011, 2012) “State of the Energy Market” for 2011 and 2012 retail prices and generator bidding behaviour; pool prices by state

CER. (2016), Email to author from CER on eligible LGCs and Accredited power station baselines, 17 March 2016

Clean Energy Council. (2011), *Clean Energy Australia report 2011*, Clean Energy Council assisted by SunWiz Consulting See www.cleanenergycouncil.org.au for installed capacity by renewable type and state, 2001 to 2011 and newly proposed renewable energy projects

Clean Energy Council. (2012), *Clean Energy Australia report 2012*, Clean Energy Council assisted by SunWiz Consulting See www.cleanenergycouncil.org.au for installed capacity by renewable type and state, 2002 to 2012 and newly proposed renewable energy projects

EGA. (2010), *Electricity Gas Australia 2010*, Energy Supply Association of Australia See www.esaa.com.au for generation by fuel type, by state and emission factors (by subscription)

EGA. (2014), *Electricity Gas Australia 2014*, Energy Supply Association of Australia See www.esaa.com.au for generation by fuel type, by state and emission factors

Frontier Economics. (2012), *Possible Future Retail Electricity Price Movements – A Report for the AEMC*, Dec 2012 See www.frontier-economics.com for LRMC residual for MRET scheme, by network area

Riesz, J. (2011), *Carbon Pricing and Electricity. What will a carbon price mean for Electricity in Australia?* QUT presentation, 29 July 2011